ERCB Energy Resources Conservation Board

ST98-2011

Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020

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The following related documents are also available from ERCB Information Services (telephone: 403-297-8311; when connected, press 2):

- CD with detailed data tables for crude oil and natural gas, as well as map of Designated Fields and Oil Sands Areas, $546
- CD with Gas Reserves Code Conversion File, $459
- CD with Gas Pool Reserve File (ASCII format), $3095
- CD with Oil Pool Reserves File (ASCII format), $1834
- Map of Designated Fields and Oil Sands Areas: 60 x 101 cm, $61; 33 x 54 cm, $29

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HIGHLIGHTS

ST98 has a new look and has been reorganized.

The sections on unconventional and conventional natural gas have been combined.

A new section, Resource Endowment, has been developed.

Imperial units have been included in the figures.

OVERVIEW

The Energy Resources Conservation Board (ERCB) is an independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the discovery, development, and delivery of Alberta's energy resources take place in a manner that is fair, responsible, and in the public interest. As part of its legislated mandate, the ERCB provides for the appraisal of the reserves and their productive capacity and the requirements for energy resources and energy in Alberta. The ERCB continues to offer a perspective on supply and demand for Alberta's electricity sector in conjunction with the Alberta Utilities Commission, which regulates this sector.

Providing information to support good decision-making is a key service of the ERCB. Making energy resource data available to everyone involved—the ERCB, landowners, communities, industry, government, and interested groups—results in better decisions that affect the development of Alberta's resources.

Every year the ERCB issues a report providing stakeholders with independent and comprehensive information on the state of reserves, supply, and demand for Alberta's diverse energy resources—crude bitumen, crude oil, natural gas, natural gas liquids, coal, and sulphur. This year's *Alberta Energy Reserves 2010 and Supply/Demand Outlook 2011-2020* includes estimates of initial established reserves (recoverable quantities estimated to be in the ground before any production), remaining established reserves (recoverable quantities known to be left), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources, and it provides some historical trends on selected commodities for better understanding of supply and price relationships.

Alberta Hydrocarbon Production in the Canadian Perspective

Alberta is Canada's largest producer of marketable natural gas. In 2010, Alberta produced 74 per cent of Canada's total production, down slightly from 76 per cent in 2009. Over the same period, Canada's second largest contributor, British Columbia, increased its share from 18 per cent to 20 per cent. **Figure 1** shows the contribution percentage breakdown by region in Canada for 2009 and 2010.

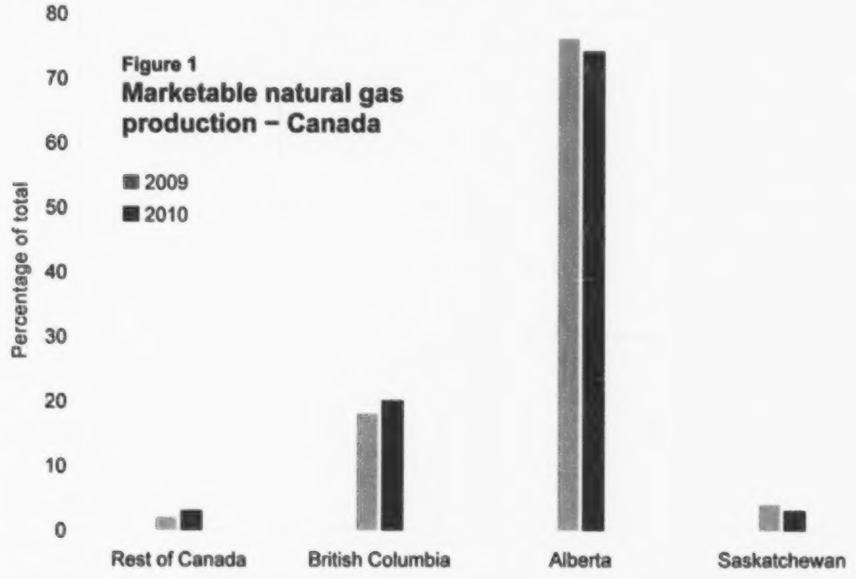
Figure 1
Marketable natural gas production – Canada

Source: National Energy Board

Alberta is also the largest contributor to Canadian oil and equivalent production and is the only contributor of synthetic crude oil and nonupgraded bitumen, which are the marketed components of raw bitumen production. **Figure 2** illustrates the contribution percentage breakdown by category and region in Canada for 2010.

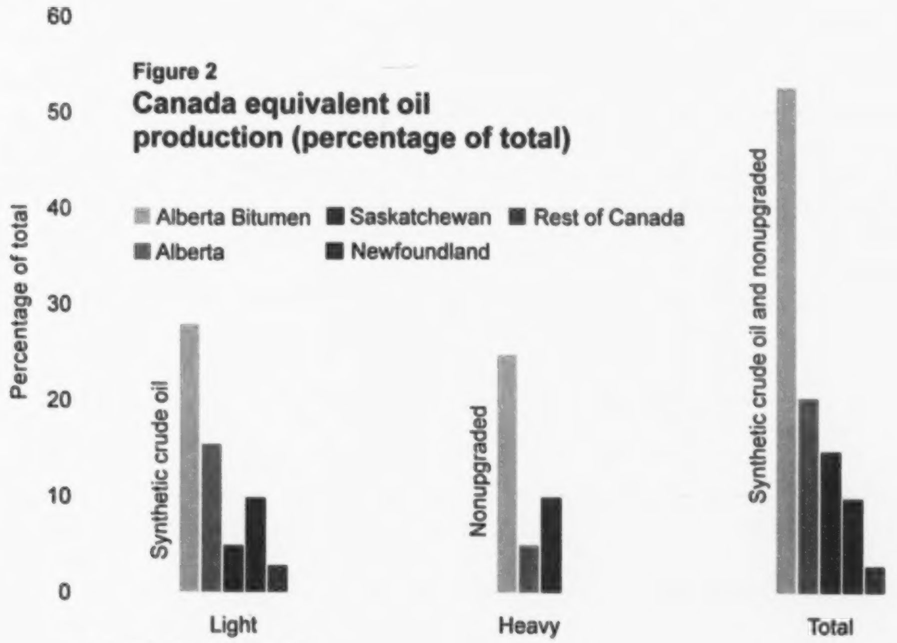
Figure 2
Canada equivalent oil production (percentage of total)

Source: National Energy Board

Only two provinces, Alberta and Saskatchewan, contribute to conventional heavy crude oil production in Canada. In 2010, Alberta accounted for nearly three-quarters of Canada's oil and equivalent production, with marketed bitumen being more than 50 per cent of the total.

Energy Prices and Alberta's Economy

Crude Oil Prices—2010

Crude oil producers experienced a relatively stable and strong price environment for most of 2010, with NYMEX WTI crude oil future near month prices generally trading in the range of US$70.00/bbl to 90.00/bbl. Robust demand growth, particularly in China and India, kept bearish inventory levels and days of forward supply from causing significant price weakness.

At the end of 2010 and into 2011, however, political instabilities in the Middle East and North Africa (MENA) region overshadowed fundamentals and created significant uncertainty in crude oil markets. Although the fundamentals point to potential global supply exceeding that of demand over the next year or two, the possibility that crude oil supply disruptions from the MENA region will result in the long-term reduction of available light, low sulphur crude oil has resulted in crude oil prices trading above US$100/bbl.

Crude Oil Prices—Forecast

The ERCB bases its analysis on the expectation that the crude oil price in North America, measured by West Texas Intermediate (WTI) crude oil, will continue to be volatile. In the longer term the ERCB expects supply and demand fundamentals will influence the market behavior, and as a result it expects the average WTI will steadily rise from US$100.00 per barrel in 2011 to an average of US$110.00 per barrel by 2020.

Natural Gas Prices—2010

Natural gas producers in North America have been, and are expected to continue to be, challenged by a weak price environment.

The low gas price environment has also resulted in the substantial decline in gas drilling in Alberta. At the same time, high crude oil prices have resulted in high drilling activity for crude oil and liquid-rich gas targets. As a result, drilling costs have not fallen to reflect the low natural gas activity levels as has been the case in the past.

Natural Gas Prices—Forecast

The ERCB bases its analysis on the expectation that natural gas prices in Alberta will average Cdn$3.50 per gigajoule in 2011 and increase to Cdn$7.00 per gigajoule by 2020.

Alberta's Economy—2010

Gross domestic product (GDP) in Alberta rebounded by 3.3 per cent in 2010, following the steep 4.5 per cent decline in 2009. Alberta real GDP growth has mostly outperformed Canadian real GDP growth over the last decade, particularly in the 2003-2007 timeframe. Average Alberta GDP growth from 2001 to 2010 was 2.5 per cent, compared with the Canadian average of 1.9 per cent.

In 2010, the total value of energy hydrocarbons and coal production increased by 15 per cent relative to 2009. The value of bitumen production, including synthetic crude oil (SCO),[1] significantly exceeded the value of natural gas production for the second year in a row.

Alberta's Economy—Forecast

Economic growth is projected to increase in 2011 as oil and gas activity recovers from the depressed levels of 2009. Oil sands related expenditures are projected to increase significantly by the middle of the decade, and when combined with a recovery in conventional oil and gas expenditures, total oil and gas investment is anticipated to approach levels equivalent to the 2006-2008 peak between 2014 and 2016.

Energy Production and Reserves in Alberta

In 2010, Alberta produced 10 885 petajoules (PJ) of energy from all sources, including renewable sources. This is equivalent to more than 4.9 million barrels per day of conventional light- and medium-quality crude oil. A breakdown of production by these energy sources is illustrated in **Figure 3**.

Raw bitumen in Alberta is produced either by mining the ore or by various in situ techniques using wells to produce bitumen. Bitumen production accounted for 78 per cent of Alberta's total crude oil and raw bitumen production in 2010. Bitumen production increased by 4 per cent at mining projects and by 14 per cent at in situ projects in 2010, resulting in an overall raw bitumen production increase of 8 per cent relative to 2009.

In 2010, total marketable natural gas production in Alberta declined by 5.6 per cent, crude oil production declined by 0.4 per cent, total natural gas liquids (NGLs) production declined by 3.6 per cent, and sulphur production declined by 5.1 per cent. Coal production declined by 1.6 percent.

While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy, less than 0.2 per cent, is also produced from renewable energy sources, such as hydro and wind power.

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[1] The upgrading process produces a variety of lighter products that are collectively referred to as SCO in this report. Naphtha, diesel fuel, and a crude similar to light crude oil in quality are the common products in the upgrading process.

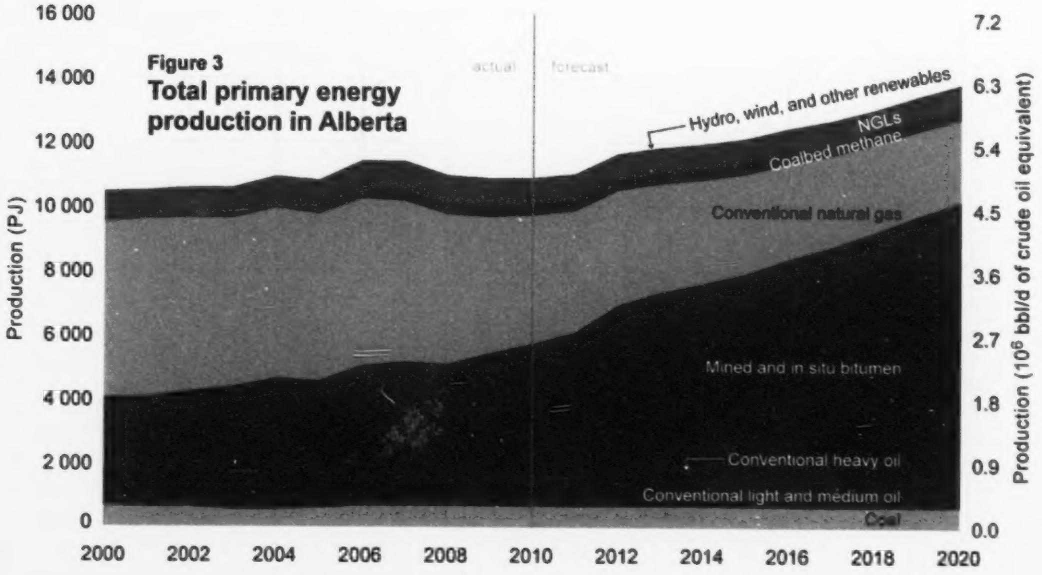


Figure 3
Total primary energy production in Alberta

The following table summarizes Alberta's energy reserves at the end of 2010.

Reserves and production summary, 2010

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in place	286 627	1 804	11 245	70.8	9 513	338	94	103
Initial established	28 092	177	2 830	17.8	5 314	189	35	38
Cumulative production	1 194	7.5	2 593	16.3	4 221	150	1.46	1.61
Remaining established	**26 898**	**169**	**237**	**1.5**	**1 093**[b]	**38.8**[b]	**33**	**37**
Annual production	93.5	0.589	26.6	0.168	116	4.1	0.032[d]	0.035[d]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[c]	223[c]	620	683

[a] Expressed as "as is" gas, except for annual production, which is at 37.4 MJ/m^3. Includes unconventional natural gas.

[b] Measured at field gate (or 35.3 trillion cubic feet downstream of straddle plant).

[c] Does not include unconventional natural gas.

[d] Annual production is marketable.

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total in situ and mineable remaining established reserves for crude bitumen is 26.9 billion cubic metres (m^3) (169.3 billion barrels), slightly less than in 2009 due to production. Only 4.3 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

In 2010, Alberta produced 49.7 million m^3 (313 million barrels) from the mineable area and 43.8 million m^3 (276 million barrels) from the in situ area, totalling 93.5 million m^3 (589 million barrels). This is equivalent to 256.3 thousand m^3 (1.6 million barrels) per day. Total raw bitumen production is projected to reach 549.6 thousand m^3 (3.5 million barrels) per day by 2020. Production from in situ bitumen projects is projected to surpass that of bitumen from mining projects by 2015.

Synthetic Crude Oil Production

In 2010, all crude bitumen produced from mining, as well as a small portion of in situ production (about 11 per cent), was upgraded in Alberta, yielding 46.1 million m^3 (290 million barrels) of SCO. About 58 per cent of total crude bitumen produced in Alberta was upgraded in the province in 2010. By 2020, SCO production is forecast to almost double to 81.5 million m^3 (513 million barrels). While this is a significant increase compared to 2010, it is expected that only 47 per cent of total crude bitumen produced in Alberta will be upgraded in the province by the end of the forecast period because of an expected narrow price differential of bitumen relative to light crude oil. Over the next 10 years, mined bitumen is projected to continue to be the primary source of the bitumen upgraded to SCO in Alberta. However, it is projected that bitumen from in situ production will be increasingly upgraded to SCO in the province. The portion of in situ production upgraded in the province will increase from 11 per cent in 2010 to 13 per cent by the end of the forecast period.

Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil is 236.9 million m^3 (1.5 billion barrels), a 3.7 per cent increase from 2009. Exploratory and development drilling, as well as new enhanced recovery schemes, added total reserves of 33.1 10^6 m^3 (208 million barrels), which replaced 124 per cent of the 2010 production. This replacement level is one of highest in several decades.

Based on its 1988 study, the ERCB estimates the ultimate potential recoverable reserves of crude oil to be 3130 million m^3 (19.7 billion barrels). Given recent reserve growth in low permeability oil plays, the ERCB believes that this estimate may be low.

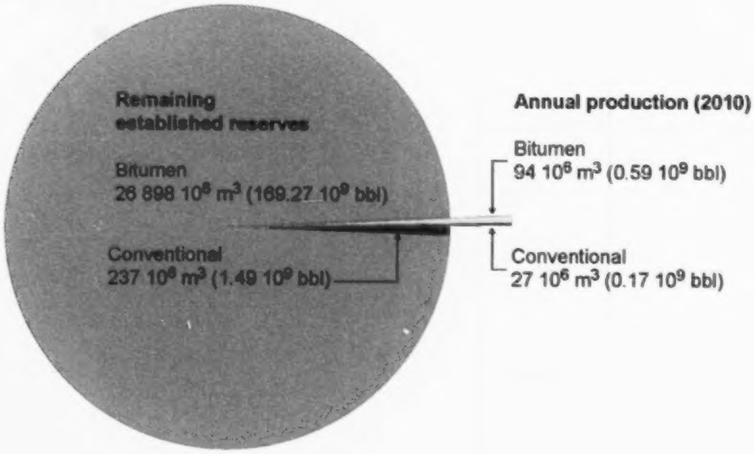
Annual production and remaining established reserves for crude bitumen and crude oil are presented in **Figure 4**.

Crude Oil Production and Well Activity

Alberta's production of conventional crude oil totalled 26.6 million m^3 (168 million barrels) in 2010. This equates to 73.0 thousand m^3 (459 thousand barrels) per day.

The number of successful oil wells drilled in 2010 was 2308, more than double 2009 levels as a result of the strong price environment. Production of light-medium crude oil remained basically flat, after steadily declining since 1995, as a result of the increased drilling activity and the use of new technology referred to as multi-stage fracturing. This new technology enhances the horizontal drilling efficiency in low permeability reservoirs.

Figure 4
Alberta oil reserves



The ERCB estimates that the number of new wells placed on production will increase to 2800 wells in 2011 and remain at this level until 2013. From 2014 to 2020, drilling activity is expected to return to recent historical levels, with the number of wells placed on production forecast to be 2500 per year.

Total Oil Supply and Demand

Figure 5 shows crude oil and equivalent supply. Alberta's 2010 supply of crude oil and equivalent reached 327.8 thousand m^3 (2.1 million barrels) per day, a 6.9 per cent increase compared with 2009. Production is forecast to reach 593.1 thousand m^3 (3.7 million barrels) per day by 2020.

A comparison of conventional oil and bitumen production over the last 10 years, as illustrated in **Figure 5**, clearly shows the increasing contribution of bitumen to Alberta's oil production.

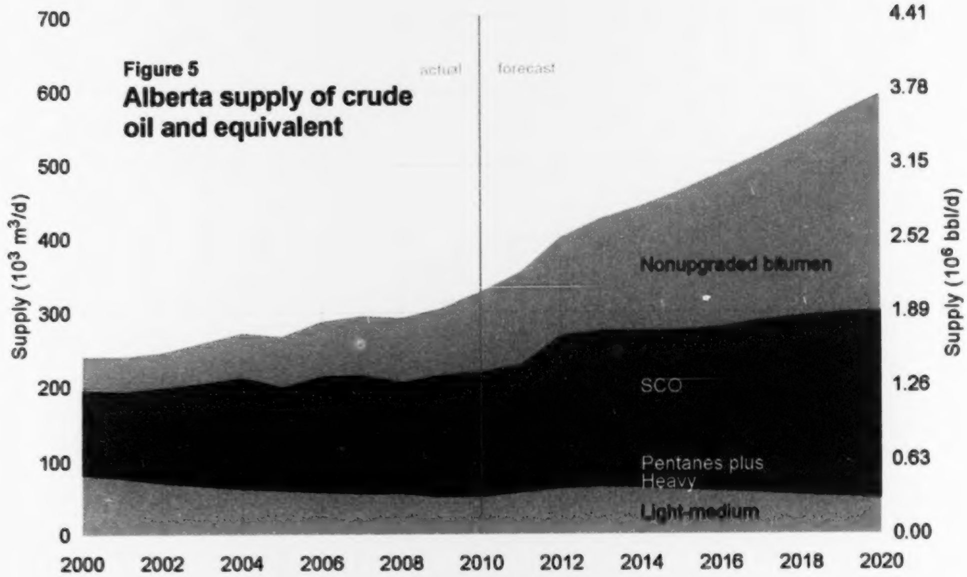


Figure 5
Alberta supply of crude oil and equivalent

The ERCB estimates that bitumen production will more than double by 2020. Over the forecast period, as illustrated in **Figure 6**, the growth in production of nonupgraded bitumen and SCO is expected to significantly more than offset the projected long-term decline in conventional crude oil. The share of SCO and nonupgraded bitumen will account for about 90 per cent of total production by 2020, compared with 2010 when the share of SCO and nonupgraded bitumen accounted for about 70 per cent of total production. Since 2003, SCO and nonupgraded bitumen has accounted for more than 50 per cent of total production.

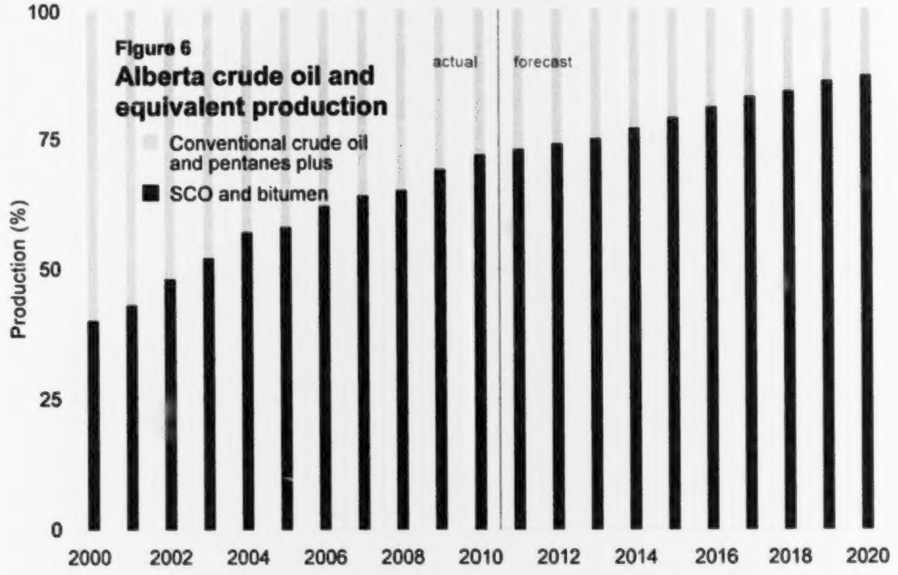
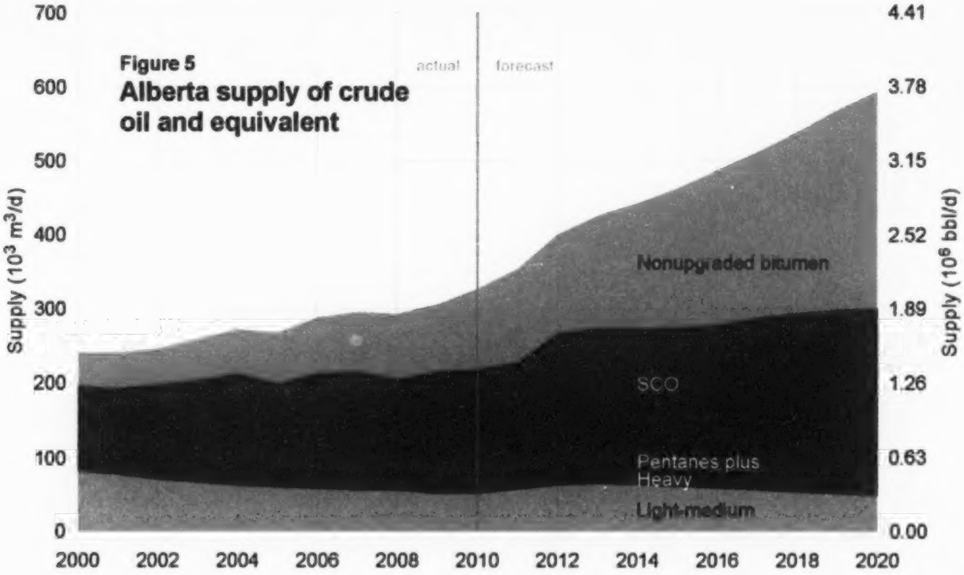


Figure 6
Alberta crude oil and equivalent production



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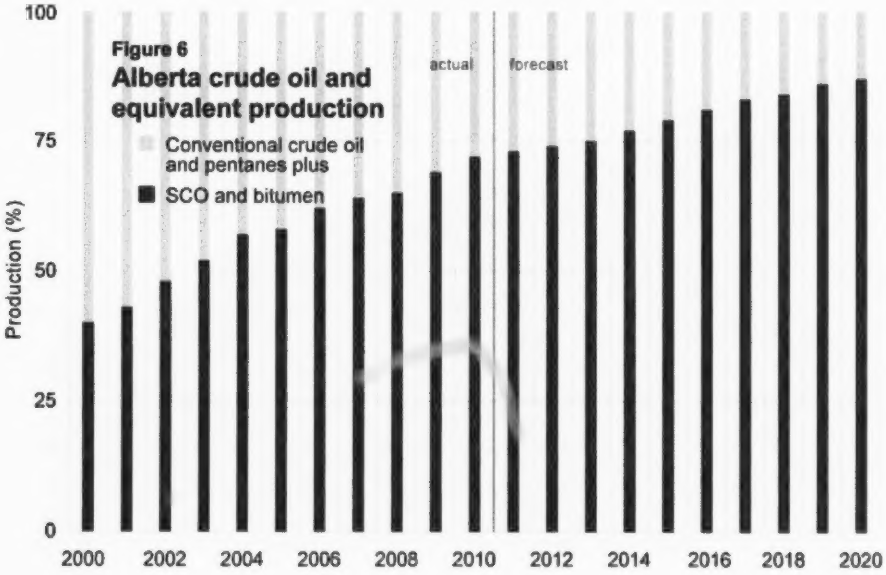


Figure 6

Alberta crude oil and equivalent production

Natural Gas

Natural gas is produced from conventional and unconventional reserves in Alberta. While most natural gas is produced from conventional sources, natural gas production from coal and shale is increasing.

Conventional Natural Gas Reserves

At the end of 2010, Alberta's remaining established reserves of conventional natural gas stood at 1025 billion m^3 (36.4 trillion cubic feet [Tcf]) at the field gate. This reserve includes some liquids that are subsequently removed at straddle plants. Reserves from new drilling replaced 46 per cent of production in 2010. This compares with 54 per cent replacement in 2009.

In March 2005, the ERCB (then known as the Alberta Energy and Utilities Board [EUB]) and the National Energy Board (NEB) jointly released *Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas*, an updated estimate of the ultimate potential for conventional natural gas. The Boards adopted the medium case, representing an ultimate potential of 6276 billion m^3, or 223 Tcf (6528 billion m^3, or 232 Tcf, at 37.4 megajoules per m^3).

Unconventional Natural Gas Reserves

The unconventional gas sources included in the natural gas section are coalbed methane (CBM) and shale gas. Given the early stage of resource development of shale gas in Alberta, the established reserves and production history of unconventional gas are exclusively CBM. CBM has been recognized as a commercial supply of natural gas in Alberta since 2002. Activity in CBM has increased from a few test wells in 2001 to more than 16 000 producing connections in 2010.

At the end of 2010, the remaining established reserves of CBM in Alberta was estimated to be 67.6 billion m^3 (2.4 trillion cubic feet), with more than half of that attributed to the Horseshoe Canyon zone (44.1 billion m^3). Currently, 86 per cent of producing CBM connections are in the Horseshoe Canyon Formation in the area between Edmonton and Calgary. In 2010, CBM and CBM hybrid well connections contributed 8 per cent of the total marketable gas production and are projected to reach 13 per cent by 2020.

Total Natural Gas Production and Well Activity

Several major factors affect natural gas production, including natural gas prices, drilling and connection activity, the accessibility of Alberta's remaining reserves, and the performance characteristics of wells. Alberta produced 319 million m^3 (11.3 Bcf) per day of marketable natural gas in 2010, a decline of 5.6 per cent from 2009. Of the total gas produced in the province, 24.7 million m^3 (0.88 Bcf) per day were from unconventional sources, primarily CBM.

There were 3099 conventional gas connections in 2010, a decrease of 19 per cent from the 3849 gas connections in 2009. The ERCB expects a gradual recovery in conventional gas connections, estimating

3300 connections in 2011. The ERCB estimates that this will increase to 4500 connections in 2014 and will remain at that level until the end of the forecast period.

CBM production in Alberta is forecast to supplement the supply of conventional natural gas. There were 1085 successful new CBM and CBM hybrid connections: 1075 in the Horseshoe Canyon and 10 in the Mannville. In 2010, new connections decreased by 38 per cent in the Horseshoe Canyon and 55 per cent in the Mannville compared with revised 2009 connections. The ERCB expects the number of new CBM and CBM hybrid connections in the Horseshoe Canyon will be 1200 connections per year over the forecast period. The number of Mannville CBM connections is forecast to be 10 connections per year from 2011 to 2013, and in conjunction with improved natural gas prices, the number is expected to increase to 15 in 2014 and remain at that level until 2016. From 2017 to 2020, 20 connections are forecast per year.

Total Natural Gas Supply and Demand

Although the decline in production was moderated in 2010 relative to 2009, the ERCB believes that new connections will not be able to sustain production levels over the forecast period. CBM production is forecast to supplement the supply of conventional gas in the province but not to replace the decline in conventional gas production.

Although natural gas supply from conventional sources is declining, sufficient supply exists to meet Alberta's demand. If the ERCB's demand forecast is realized, Alberta's natural gas requirement will be 77 per cent of total Alberta production by the end of the forecast period.

As Alberta requirements continue to increase and production continues to decline, less gas is available for removal from the province. The ERCB's mandate requires that the natural gas requirements for Alberta's core market (defined as residential, commercial, and small industrial gas consumers) be met over the long term before any new gas removal permits are approved. Alberta's marketable gas production (at 37.4 MJ/m^3) and demand are shown in **Figure 7**.

Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane are estimated to be 113 million m^3 (716 million barrels) as of year-end 2010. This estimate considers the recovery of liquid ethane from raw gas extracted at field and straddle plants in Alberta based on existing technology and market conditions.

In 2010, the production of specification ethane decreased to 34.2 thousand m^3 (217 thousand barrels) per day from 35.1 thousand m^3 (222 thousand barrels) per day in 2009. All of the ethane was used as feedstock for Alberta's petrochemical industry. Although the forecast ethane supply from conventional

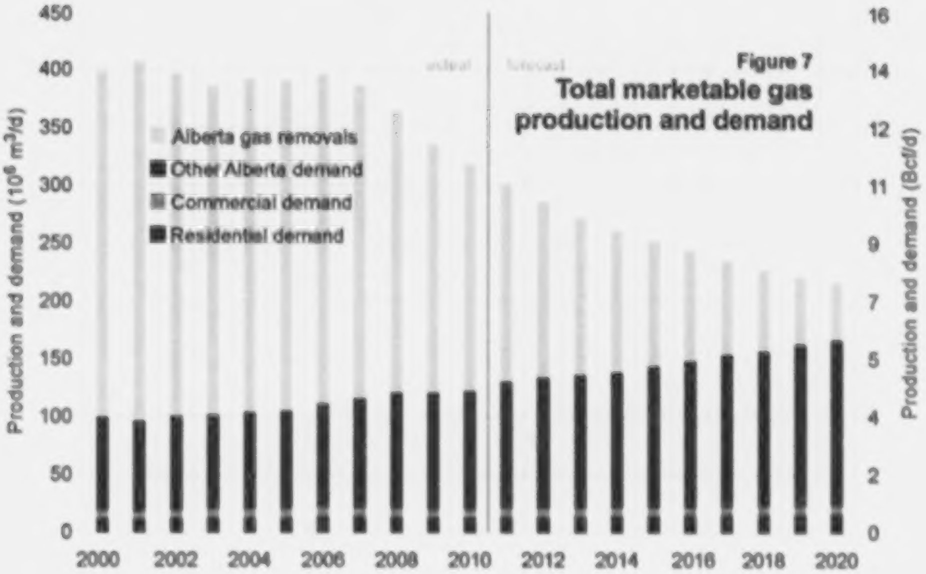


Figure 7
Total marketable gas production and demand

gas crosses over the demand curve before the end of the forecast, incremental ethane supply from oil sands off-gas has been forecast to meet demand over the forecast period.

The remaining established reserves of other NGLs—propane, butanes, and pentanes plus—is 148 million m^3 (932 million barrels) in 2010. The supply of propane and butanes is expected to meet demand over the forecast period. Due to the tightness of the supply of pentanes plus, alternative sources of diluent are being used by industry to dilute the heavier crude to meet pipeline quality.

The remaining established reserves of sulphur decreased in 2010 by 2.6 per cent, from 181 million tonnes in 2009 to 176 million tonnes. Sulphur is recovered from the processing of natural gas and the upgrading of bitumen. About 89 per cent of total marketed sulphur in 2010 was shipped outside the province, with 26 per cent going to the U.S., 61 per cent going offshore, and the remainder going to the rest of Canada. Sulphur demand is expected to remain flat in 2011 and increase to 5.5 million tonnes for the years 2012 and the remainder of the forecast period. It is projected that with relatively flat production over the forecast period, minimal stockpile withdrawals are required to meet forecast demand.

Coal

The current estimate for remaining established reserves of all types of coal is about 33.3 billion tonnes (36.7 billion tons). This massive energy resource continues to help meet the energy needs of Albertans, supplying fuel for about 59 per cent of the province's electricity generation in 2010. Alberta's total marketable coal production in 2010 was 31.7 million tonnes (35.0 million tons), most of which is subbituminous coal destined for mine mouth power plants. This total production is slightly lower than production in 2009, primarily due to the closure of the Whitewood mine in 2010. Alberta's coal reserves represent more than a thousand years of supply at current production levels.

The small portion of Alberta coal production that was exported from the province in 2010 can be separated into thermal coal exports and metallurgical coal exports. The export market for metallurgical coal remained strong in 2010 due to the continued, though reduced, demand for steel production in the Pacific Rim countries.

Electricity

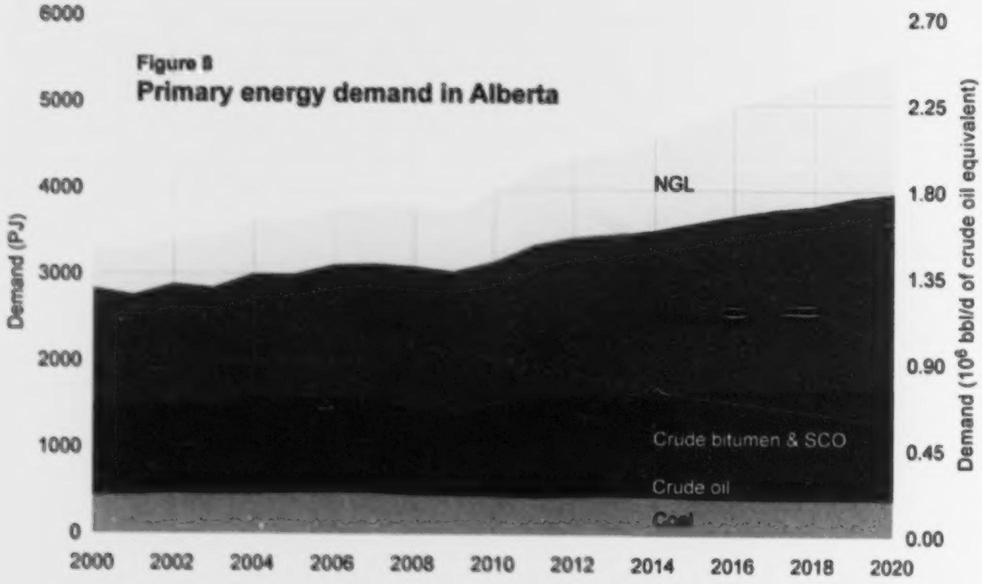
Electricity generating capacity in Alberta was just under 13 100 megawatts (MW) in 2010, an increase over 2009 of 2.4 per cent, with most of the addition comprising three new wind power facilities with capacities totalling 214 MW. By the end of the forecast period, the ERCB expects total electricity generating capacity in Alberta to be more than 15 900 MW.

In 2010, total electricity generation reached 70 586 gigawatt hours (GWh), slightly higher than the 69 262 GWh in 2009. Alberta imported 2366 GWh of electricity and exported 464 GWh. Over the forecast period, total electricity generation is expected to grow by an average of 2.8 per cent per year to more than 94 000 GWh by 2020.

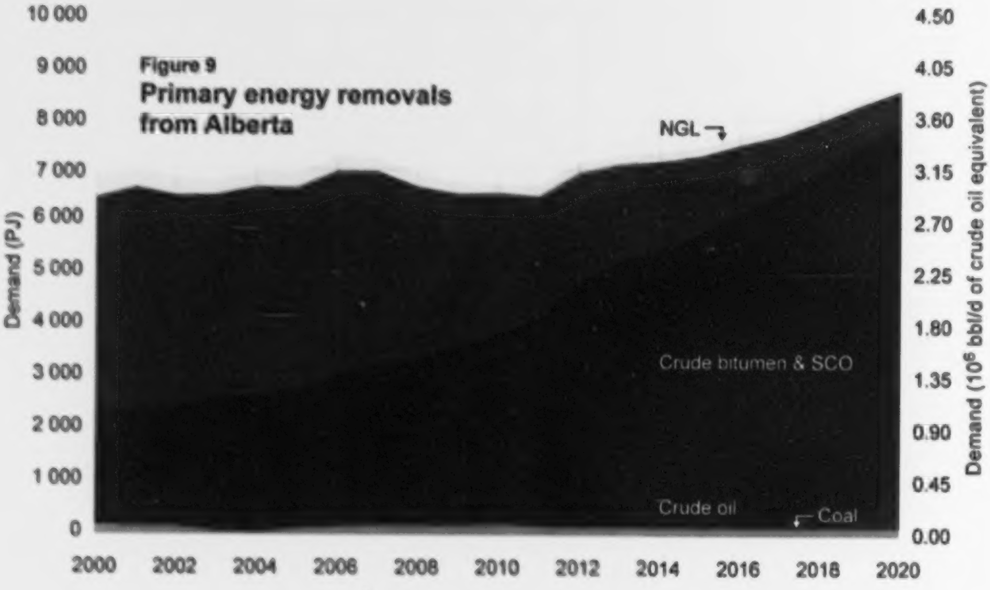
Total electricity demand in Alberta (retail sales, direct connect sales, and industrial on-site use) reached 68 011 GWh in 2010, an increase of 1.2 per cent from 2009. However, expected growth in industrial electricity demand, through both wholesale purchases and on-site generation, will average 2.8 per cent per year over the forecast period, similar to the average growth in overall demand. The oil sands sector is expected to dominate load growth.

Primary Energy Demand

Alberta's primary energy demand by energy type is shown in **Figure 8**. While 2011 demand for coal is fairly flat at 2010 levels, more conventional crude oil, natural gas, bitumen, and SCO will be consumed in the province. Total primary energy consumption in 2010 is equivalent to 1.9 million barrels per day of crude oil. This amount is projected to increase to 2.5 million barrels per day by 2020.



The primary energy removals from Alberta are shown in **Figure 9**. Most shipments are to the United States. Total primary energy removals from the province are expected to reach 3.9 million barrels of crude oil equivalent by 2020, up from 3.0 million barrels in 2010.



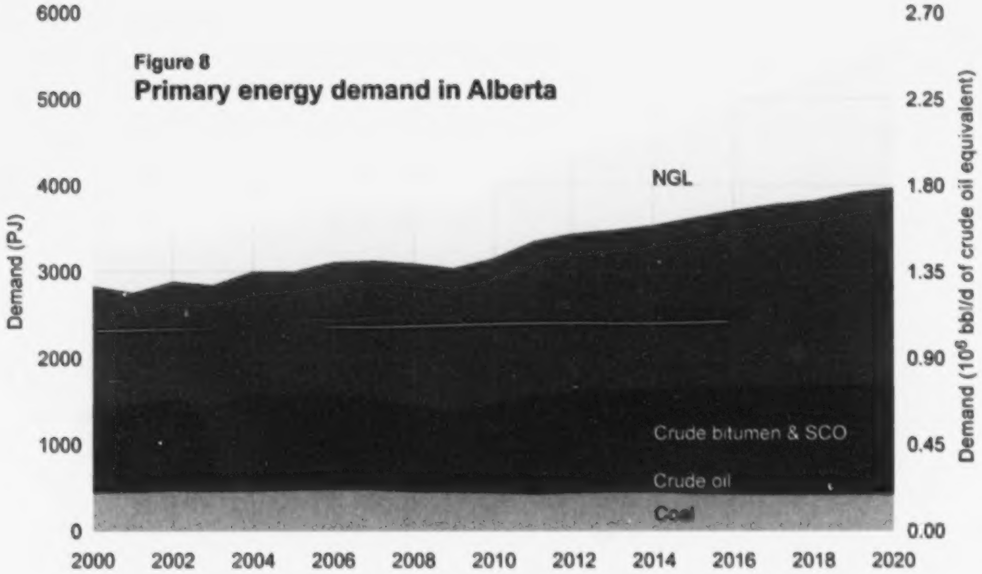


Figure 8
Primary energy demand in Alberta

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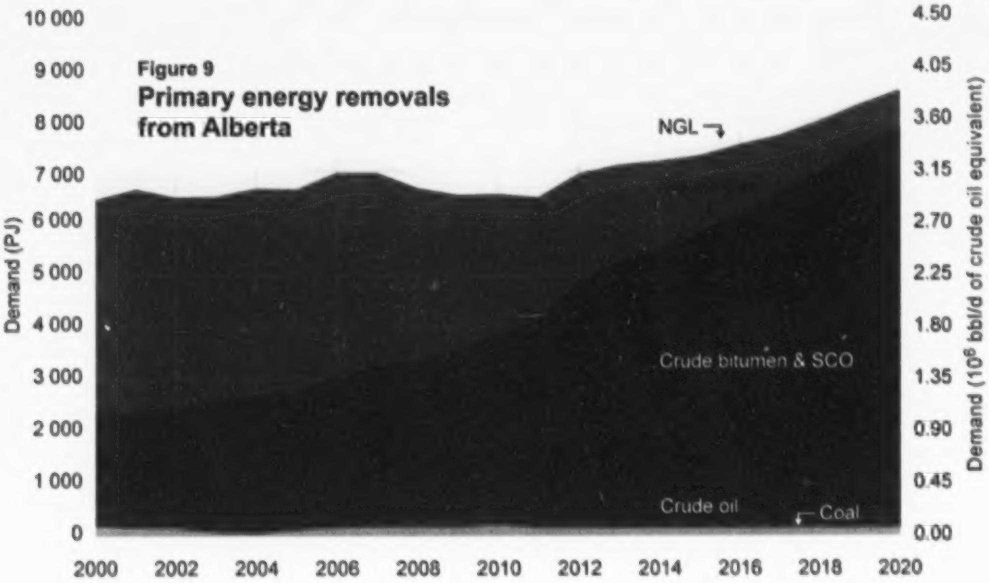


Figure 9
Primary energy removals from Alberta

Energy Trends

Oil and Gas Drilling Activity

Drilling activity in the province increased rapidly from 1993, reaching a peak in 2005. Drilling activity from 2007 to 2009, particularly for natural gas, declined because of increasing costs and weak natural gas prices. In 2010, drilling activity for crude oil more than doubled as a result of strong crude oil prices, while other drilling activity showed slight improvements over the previous year. **Figure 10** illustrates the province's drilling history over the past six decades.

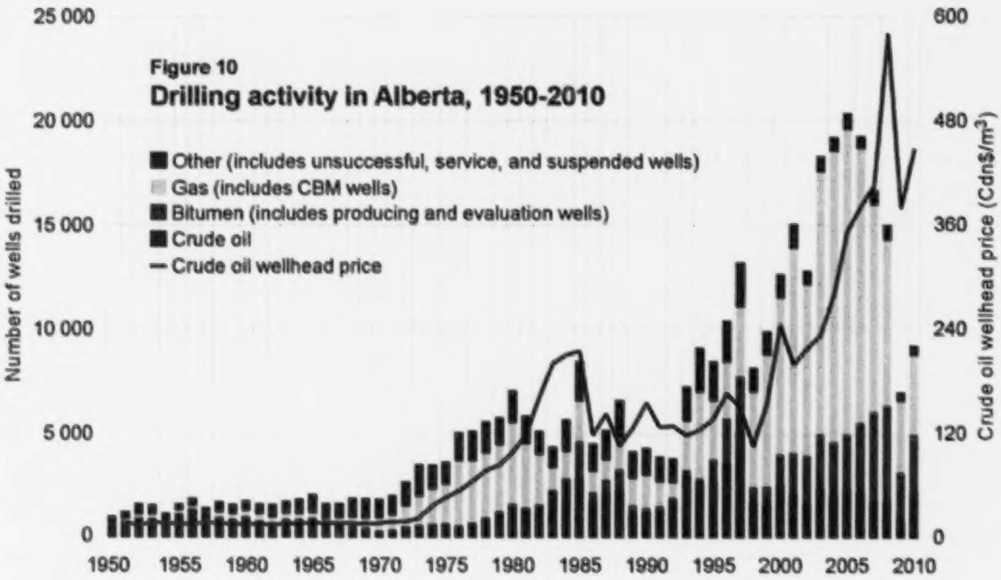


Figure 10

Drilling activity in Alberta, 1950-2010

Crude Oil and Bitumen

Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 11**. Production from the Turner Valley field, which was discovered in 1914, accounted for 99 per cent of production in 1938 and 89 per cent of production in 1946. The discovery of Leduc Woodbend in 1947 jumpstarted Alberta crude oil production, which culminated in 1973 with peak production of 227.4 thousand m^3/day. Major events that affected Alberta's crude oil production and crude oil prices are also noted in the figure. Factors affecting current crude oil prices and the forecast are found in Section 1.

Figure 12 shows the historical mined bitumen and SCO production, beginning with the start-up of Great Canadian Oil Sands (Suncor) in 1967. This was followed by Syncrude in 1978 and the Alberta Oil Sands Project (Shell Albian Sands and Shell Scotford Upgrader) in 2003. The Horizon Project (CNRL) commenced mining operations in late 2008 and produced SCO in 2009. SCO from the Long Lake project (Nexen/OPTI) also came on stream in 2009. This is the first project that is based on in situ bitumen recovery and field upgrading. The figure also shows the price of SCO since 1971. SCO generally receives a price premium relative to light crude oil.

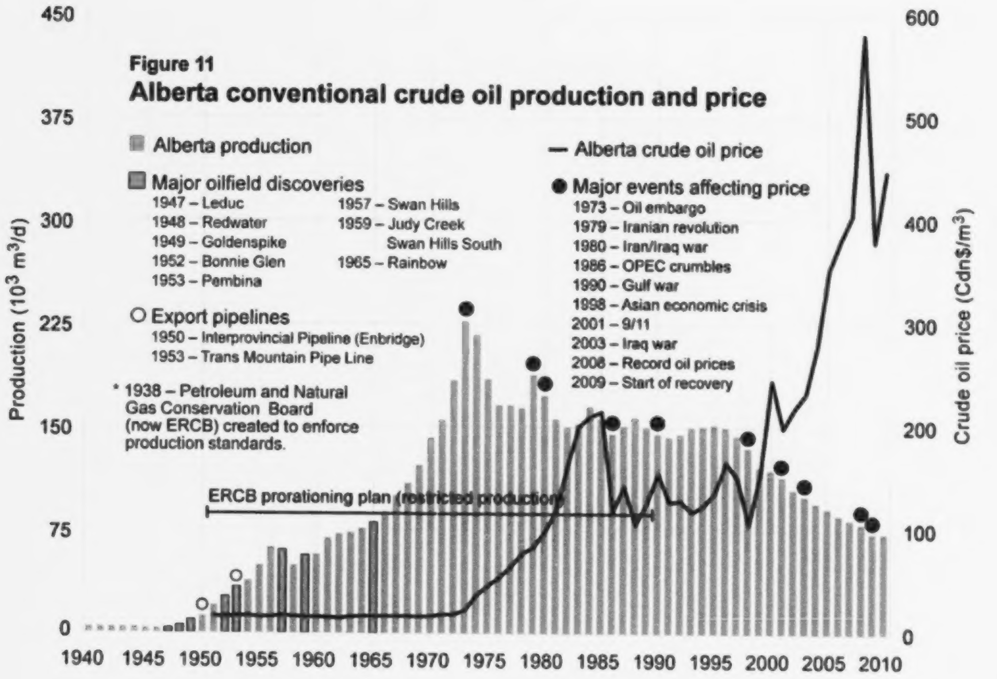


Figure 11
Alberta conventional crude oil production and price

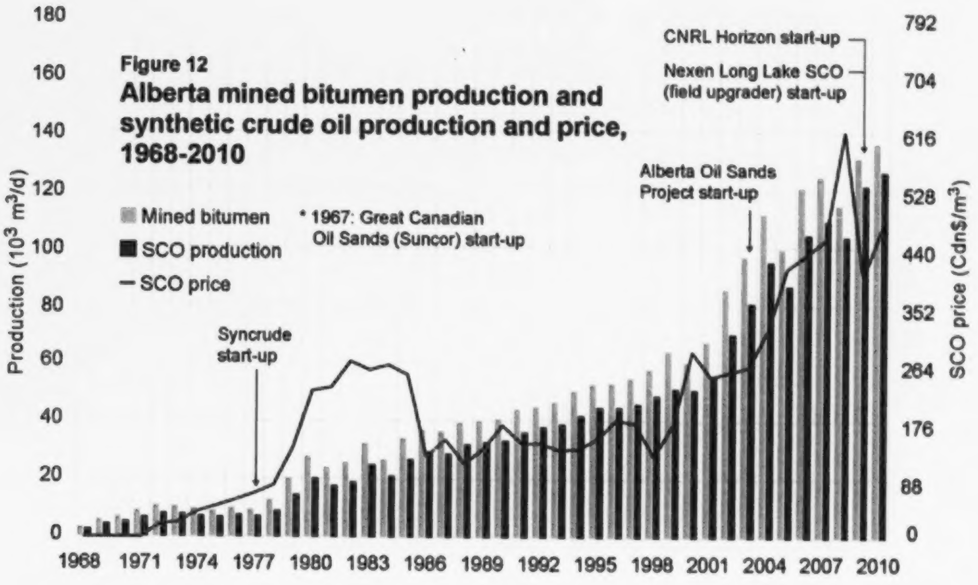


Figure 12
Alberta mined bitumen production and synthetic crude oil production and price, 1968-2010

Historical production and the price of in situ bitumen are shown in **Figure 13**. Imperial's Cold Lake project facility, which uses the cyclic steam stimulation recovery method, has historically accounted for most in situ production. Differentials between Alberta light and heavy crudes narrowed significantly from 2008 to 2010. The bitumen/light-medium differential averaged 17 per cent from 2008 to 2010, compared to 44 per cent over the five-year average from 2003 to 2007. In 2010, the price of heavy crude in Alberta increased at a slower rate than light and medium crude, leading to a slight widening of the differential between light and heavy from 14 to 16 per cent. Similarly, the differential between light-medium crude oil and crude bitumen widened from 17 to 21 per cent from 2009 to 2010. **Figure 12** and **Figure 13** demonstrate that unlike conventional resources of oil and gas, bitumen reserves are less mature and production responds to price increases more directly.

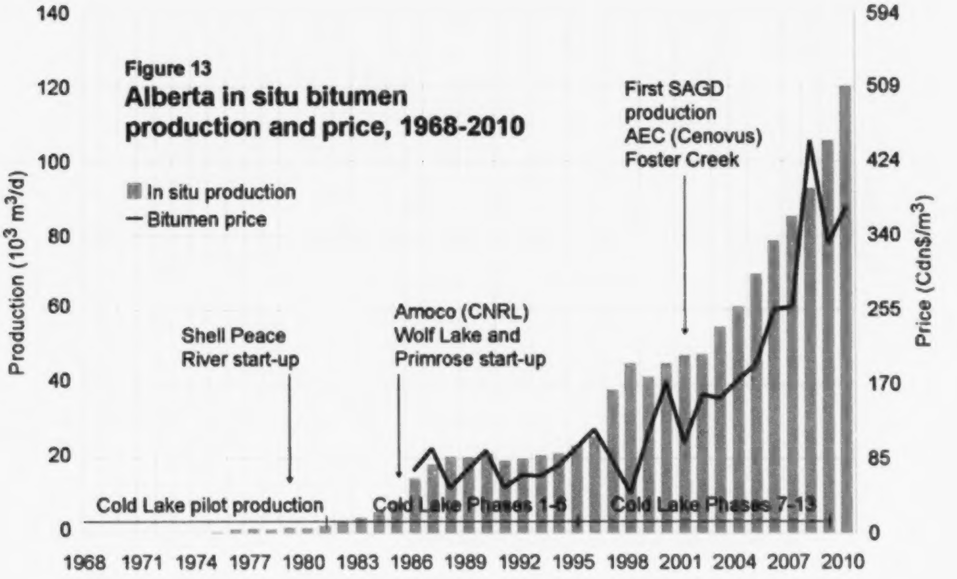


Figure 13
Alberta in situ bitumen production and price, 1968-2010

Natural Gas

Natural gas as a commodity has an interesting past, as seen in **Figure 14**, which shows historical gas production and price. In the 1950s and 1960s, it was mainly produced as a by-product of crude oil production and was flared as a waste product. During this period, natural gas prices were low. In the early 1970s, when OPEC increased crude oil prices, natural gas prices started to increase.

In 1980, through the National Energy Program, the federal government imposed regulated gas prices tied to crude oil prices based on their relative calorific values. High gas prices in the 1980s spurred drilling, which resulted in a significant oversupply of reserves.

In 1985, natural gas prices were deregulated in Canada. The removal of set prices, the oversupply of reserves, and the drop in demand because of recession resulted in the decline of natural gas prices for the rest of the decade.

In the early 1990s, natural gas prices became more market responsive. Development of trading points in Chicago, New York, and the Henry Hub in the U.S. in the late 1980s and AECO "C" in the early 1990s facilitated natural gas being traded as a true commodity. In recent years, shale gas production in the United States has contributed significantly to the growth in natural gas production, reversing the trend of annual U.S. production declines. The influence of increased supply and lagging demand has resulted in low gas prices in North America and contributed to the reduction in natural gas activity in Alberta.

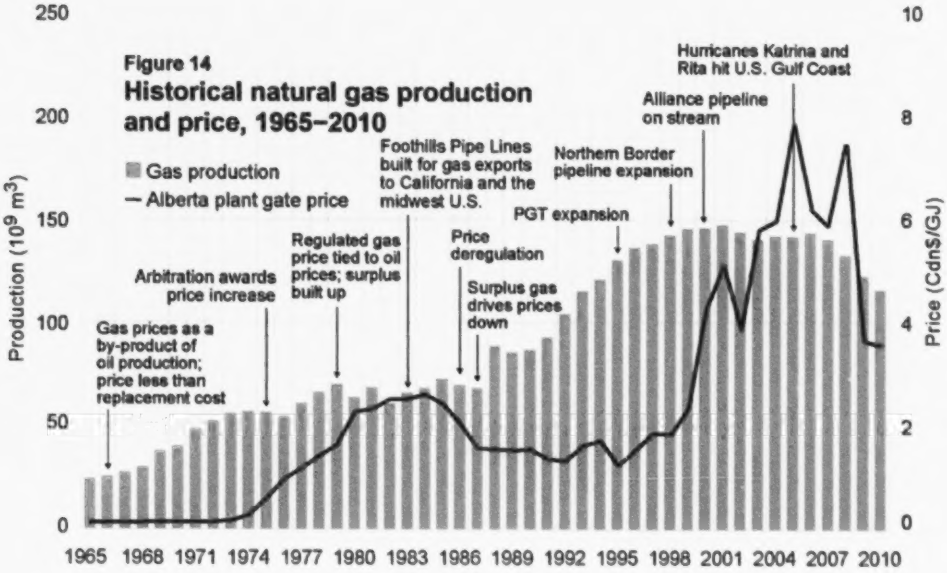


Figure 14
Historical natural gas production and price, 1965–2010

Sulphur

Figure 15 illustrates sulphur closing inventories at processing plants and oil sands operations from 1971 to 2010. Sulphur prices in this period are also shown, adding insight into how prices affect the growth or decline in sulphur inventories. Because of logistics costs, Canadian sulphur producers do not remelt and remove inventories unless they are assured a "good price." When international demand is high and international prices follow, Alberta sulphur blocks are used as an additional source to increase the supply. This is usually sufficient to bring things back into balance, reduce prices, and stop the remelting of inventories.

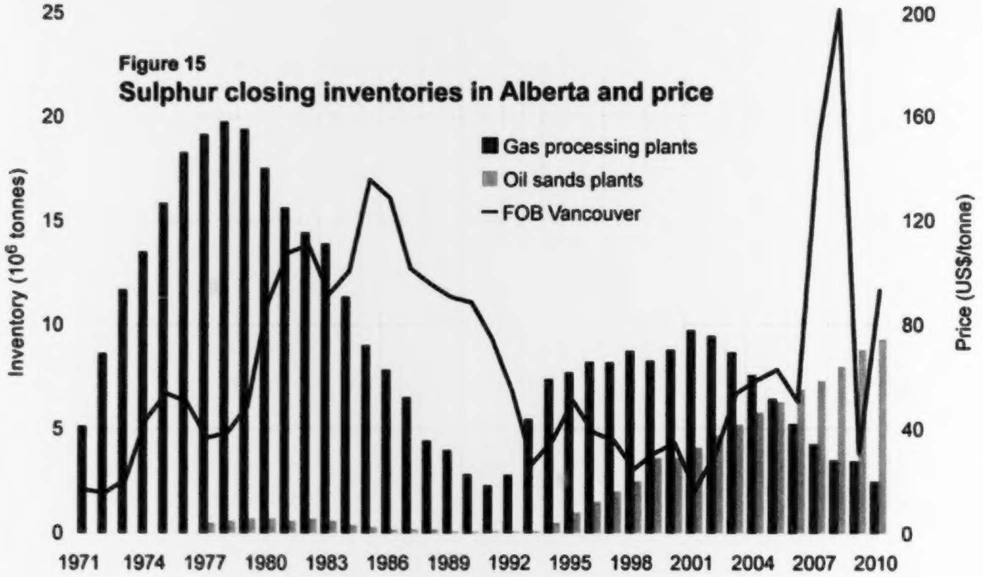


Figure 15
Sulphur closing inventories in Alberta and price

Coal

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical raw coal production by type is illustrated in **Figure 16**. The export prices for coal are based on bituminous thermal coal contract prices for Australian coal shipped to Japan (often referred to

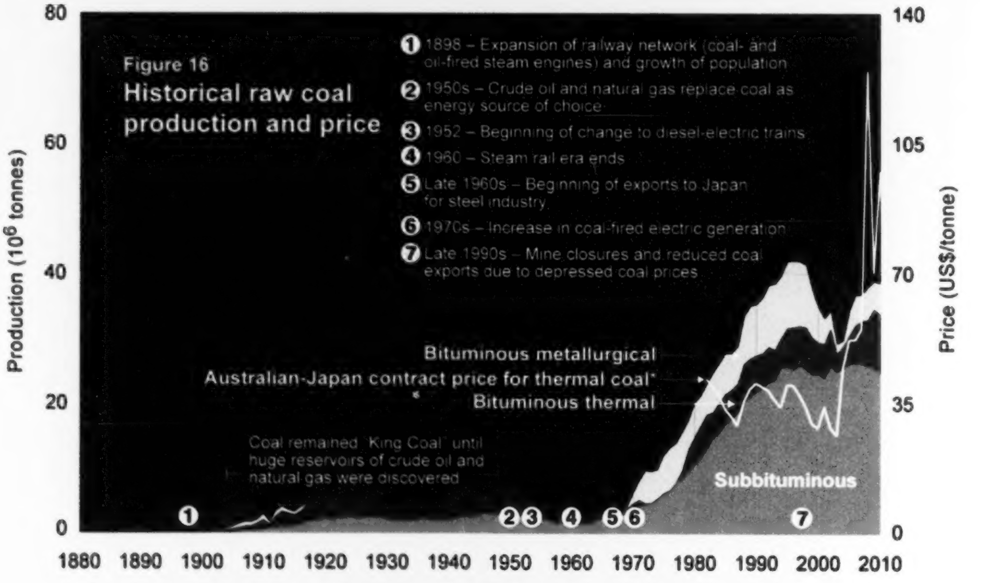


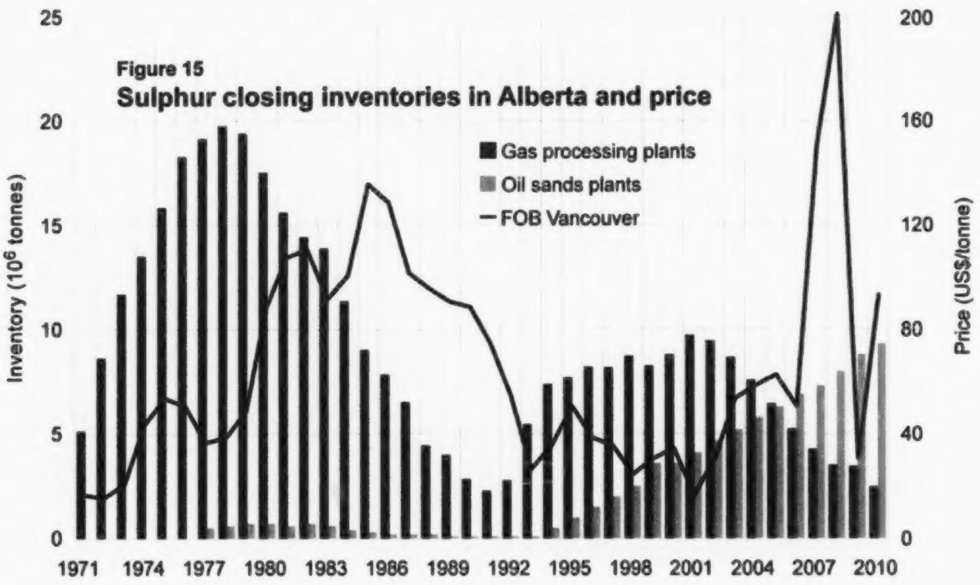
Figure 16
Historical raw coal production and price

① 1898 – Expansion of railway network (coal- and oil-fired steam engines) and growth of population
② 1950s – Crude oil and natural gas replace coal as energy source of choice
③ 1952 – Beginning of change to diesel-electric trains
④ 1960 – Steam rail era ends
⑤ Late 1960s – Beginning of exports to Japan for steel industry
⑥ 1970s – Increase in coal-fired electric generation
⑦ Late 1990s – Mine closures and reduced coal exports due to depressed coal prices

Coal remained "King Coal" until huge reservoirs of crude oil and natural gas were discovered

80
60
40
20
0
Production (10⁶ tonnes)
140
105
70
35
0
Price (US$/tonne)
Bituminous metallurgical
Australian-Japan contract price for thermal coal*
Bituminous thermal
Subbituminous
①
②③
④
⑤⑥
⑦
1880
1890
1900
1910
1920
1930
1940
1950
1960
1970
1980
1990
2000
2010

*Australian Bureau of Agricultural and Resource Economics (ABARE)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Sulphur closing inventories in Alberta and price

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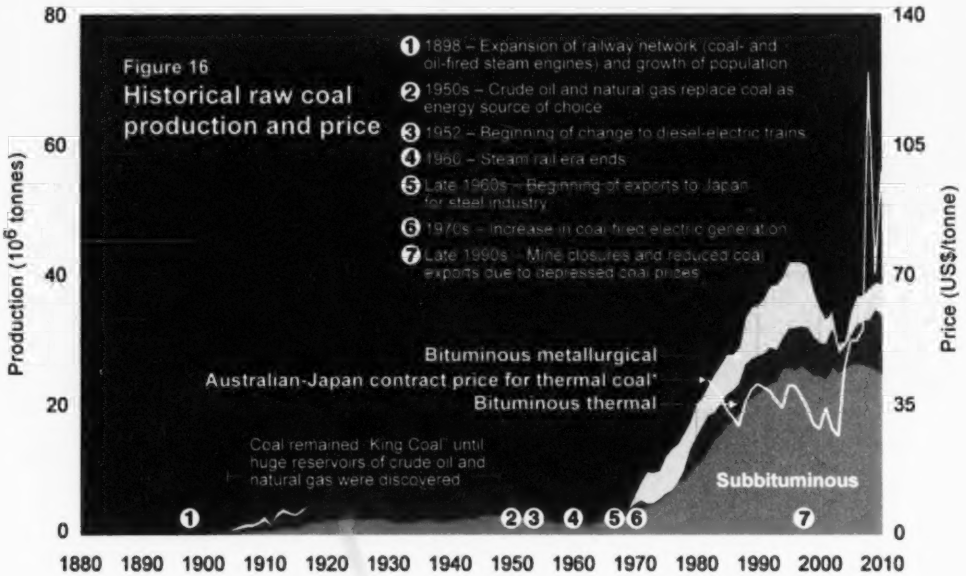


Figure 16
Historical raw coal production and price

*Australian Bureau of Agricultural and Resource Economics (ABARE) as Newcastle thermal coal) and are used as a benchmark in this report. Australia is the world's largest exporter of coal. Subbituminous coal produced in Alberta is mainly used in the province for power generation, and cost-of-service contracts with the mining companies generally determine the cost (price) of subbituminous coal.

1 // ECONOMICS

HIGHLIGHTS

WTI crude oil prices averaged US$79.61 per barrel (bbl) in 2010, compared with US$62.09/bbl in 2009, an increase of 28 per cent.

Alberta wellhead natural gas prices averaged $3.57 per gigajoule (GJ) in 2010, compared with $3.65/GJ in 2009, a decrease of 2 per cent.

There were 9233 wells drilled in Alberta in 2010, compared with 6980 in 2009, a 32 per cent increase.

Energy production is generally affected by remaining reserves, energy prices, demand, and costs. Energy demand, in turn, is determined by such factors as economic activity, standard of living, seasonal temperatures, and population. Furthermore, the activity in Alberta's energy sector is heavily influenced by demand and supply conditions and economic activity in the United States, the largest importer of Alberta's fossil fuels.

This section introduces some of the main variables affecting energy supply and demand and sets the stage for discussions in the report. Alberta crude oil prices are determined globally and relate to West Texas Intermediate (WTI) and the Organization of Petroleum Exporting Countries (OPEC) reference basket price.

The section begins with a review of the OPEC crude oil basket reference price and a summary of factors that will influence benchmark oil prices in the years to come. It also discusses the current global oil supply and demand picture, including projections for 2010 and 2011 based on research conducted by the International Energy Agency (IEA).

Energy prices in North America and oil and gas production costs in Alberta are discussed. The section concludes with a summary of Alberta's and Canada's recent economic performance, along with the ERCB's outlook on Alberta's economic growth.

1.1 Energy Prices

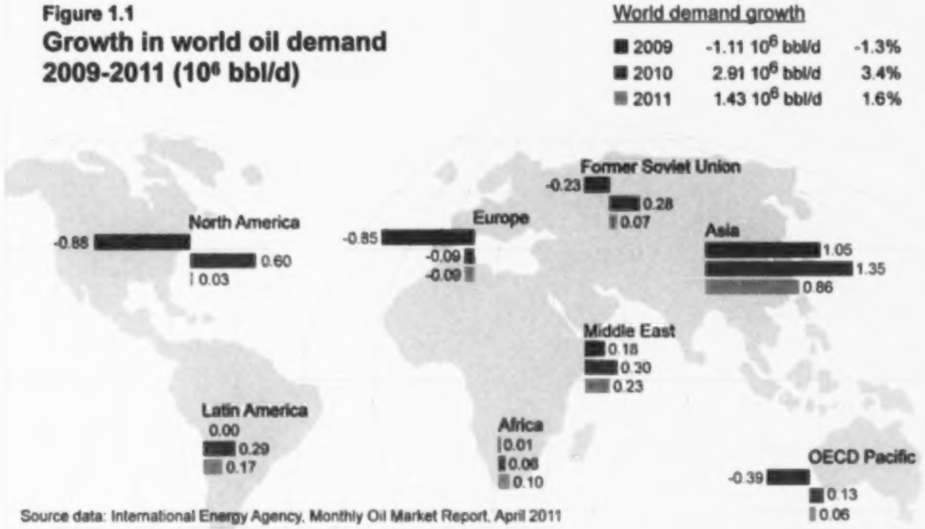
1.1.1 World Oil Market

World oil demand grew strongly in 2010 from the depressed levels of 2009, as the world economy continued to recover from the financial crisis of 2008. Global oil demand is estimated to have decreased by 1.1 million (10^6) bbl/d in 2009, followed by a substantial increase of 2.9 10^6 bbl/d in 2010, to a total of 87.9 10^6 bbl/d. In 2010, the largest increases in oil demand were in Asia, followed by North America, with only European oil demand showing a slight decline.

Figure 1.1 illustrates historical growth in oil demand across the globe between 2009 and 2010, along with the most recent forecast for 2011 by the IEA.

As shown in **Figure 1.1**, the IEA projects global crude oil demand to increase by 1.4 10^6 bbl/d in 2011, or 1.6 per cent. The recovery in the world economy has resulted in world oil demand resuming its long-term growth trajectory.

Figure 1.1
Growth in world oil demand 2009-2011 (10^6 bbl/d)


World demand growth
■ 2009 -1.11 10⁶ bbl/d -1.3%
■ 2010 2.91 10⁶ bbl/d 3.4%
■ 2011 1.43 10⁶ bbl/d 1.6%
North America
-0.88
0.60
0.03
Europe
-0.85
-0.09
-0.09
Former Soviet Union
-0.23
0.28
0.07
Asia
1.05
1.35
0.86
Middle East
0.18
0.30
0.23
Latin America
0.00
0.29
0.17
Africa
0.01
0.06
0.10
OECD Pacific
-0.39
0.13
0.06

Source data: International Energy Agency, Monthly Oil Market Report, April 2011

Figure 1.2 depicts the monthly average OPEC crude oil basket reference price and the monthly average WTI price at Cushing for 2010.[1] The OPEC reference price averaged US$76.01/bbl in January 2010, falling back to average US$72.51 in July 2010 and then increasing to average US$88.56/bbl in December 2010, with a yearly average of US$77.45/bbl. Prices strengthened throughout the fourth quarter in response to continued economic and world oil demand growth.

From 2003 to 2008, WTI averaged US$3/bbl to $6/bbl higher than the OPEC reference price on an average annual basis, reflecting quality differences, the cost of shipping, and localized market conditions. In 2009, the premium of WTI to the OPEC basket narrowed, averaging approximately US$1/bbl, as WTI prices were affected by high North American crude oil storage levels and depressed market conditions. In 2010, WTI moved to a US$2/bbl average annual premium to the OPEC basket. However, more recently in 2011, WTI is trading at a significant discount to the OPEC basket, averaging US$6.88/bbl in the first quarter of 2011. This discount reflects the land-locked nature of WTI, significant increases in North American supplies, and the lack of pipeline capacity to move crude oil away from Cushing, Oklahoma to the U.S. Gulf Coast. The discount of WTI to the OPEC basket will likely remain until those factors are overcome.

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[1] OPEC calculates a production-weighted reference price, referred to as the OPEC reference basket price.

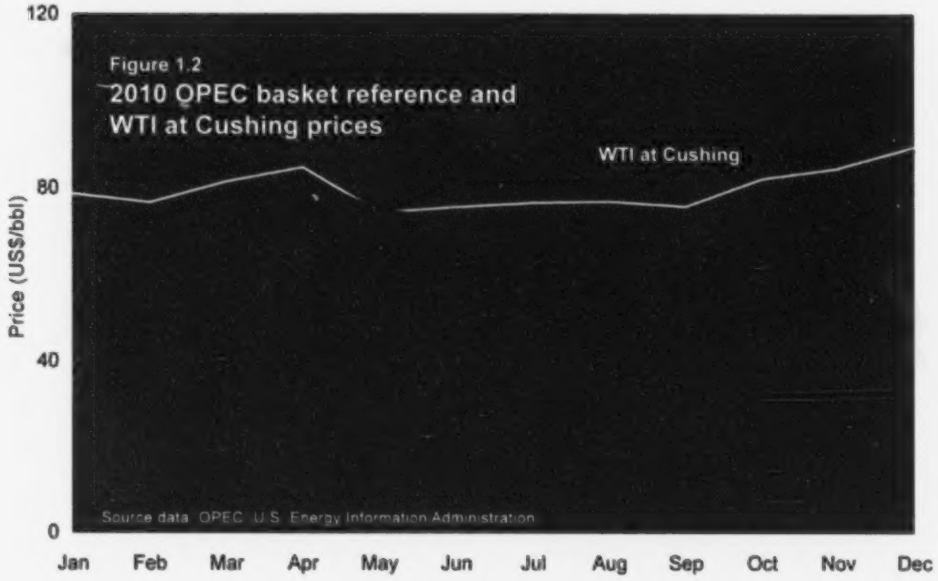
Figure 1.2
2010 OPEC basket reference and WTI at Cushing prices

Source data: OPEC, U.S. Energy Information Administration

In 2010, OPEC produced 29.2 10^6 bbl/d, compared with 28.7 10^6 bbl/d in 2009. OPEC production in 2010 was approximately 34 per cent of total world oil demand.[2] Including OPEC natural gas liquids, OPEC produced 34.0 10^6 bbl/d, or 39 per cent of total oil demand.

1.1.2 North American Energy Prices

1.1.2.1 North American Crude Oil Prices

North American crude oil prices are most directly related to the WTI crude oil price at Cushing, which is the underlying physical commodity market for the New York Mercantile Exchange (NYMEX) for light crude oil contracts. WTI crude has an API of 40 degrees and a sulphur content of less than 0.5 per cent. **Figure 1.3** shows historical and forecast WTI prices at Cushing.

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[2] Statistics obtained from OPEC *Monthly Oil Market Report* (April 2011).

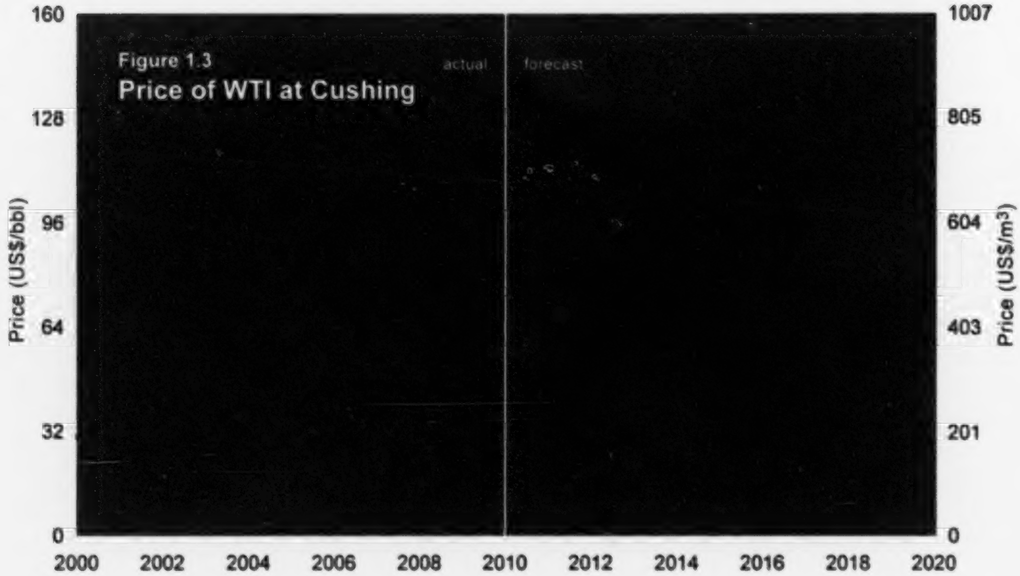


Figure 1.3
Price of WTI at Cushing

The ERCB is projecting that WTI will average US$100 in 2011 with a possible range from US$90 to US$110. Prices in early 2011 were elevated because of the political unrest in the Middle East and North Africa area, which has resulted in the disruption of Libyan crude oil exports. As illustrated, the forecast price of WTI is expected to increase throughout the forecast period, as increasing crude oil demand exerts upward pressure on supplies and on price. By 2020, WTI prices are projected to be $US110/bbl within a possible forecast range of US$99/bbl to US$121/bbl.

The ERCB calculates light crude oil prices at Edmonton, Alberta, as a function of WTI prices at Cushing. The WTI Cushing price is adjusted for transportation and other charges between Edmonton and Cushing, for the exchange rate, and for crude quality. The Edmonton reference price is based on WTI quality. **Figure 1.4** shows historical and forecast prices for Alberta light crude at Edmonton in Canadian dollars.

Table 1.1 compares 2009 and 2010 Alberta light-medium, heavy, and bitumen crude oil prices. **Figure 1.5** illustrates the average monthly price of Alberta light-medium crude, heavy crude, and bitumen.

Table 1.1 Alberta wellhead annual average crude oil reference prices

Reference price (Cdn$/bbl)	2010	2009
Alberta light-medium	74.74	63.09
Alberta heavy crude reference price	62.96	54.46
Alberta bitumen reference price	59.05	52.57

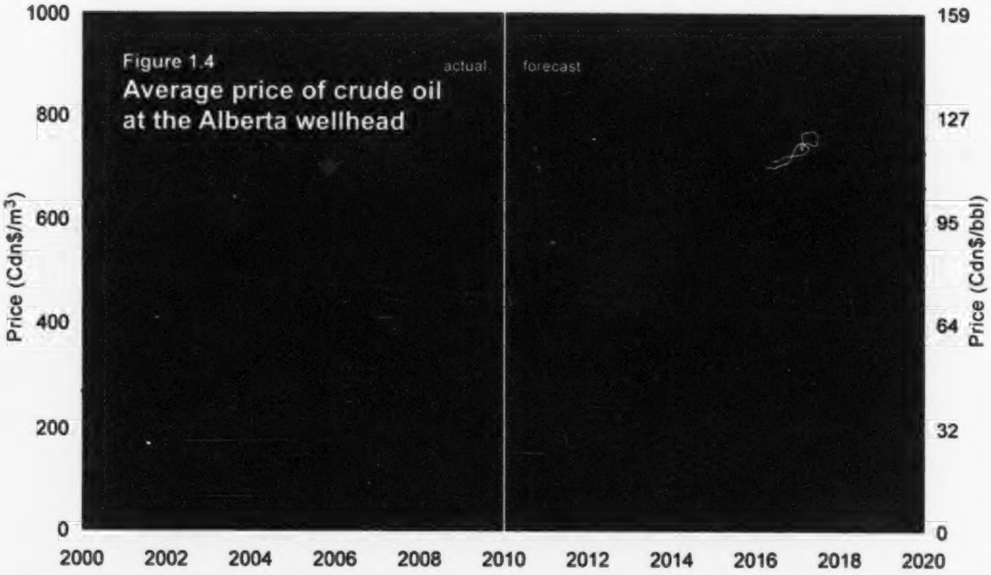


Figure 1.4
Average price of crude oil at the Alberta wellhead

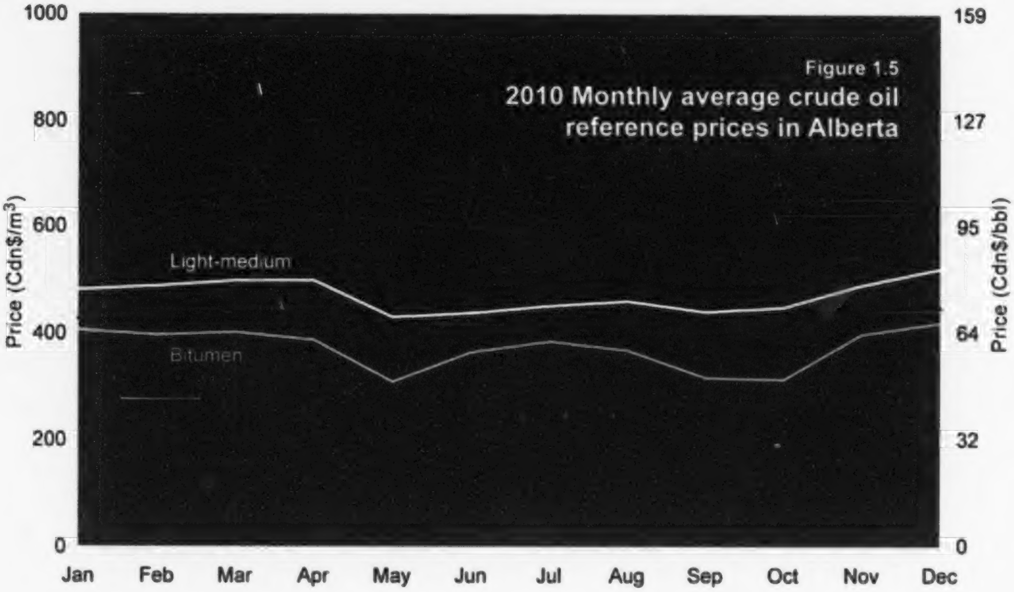


Figure 1.5
2010 Monthly average crude oil reference prices in Alberta

Differentials between Alberta light and heavy crudes narrowed significantly from 2008 to 2010. The bitumen/light-medium differential averaged 22 per cent from 2008 to 2010, compared with 44 per cent over the five-year average from 2003 to 2007. In 2010, the price of heavy crude in Alberta increased at a slower rate than light and medium crude, leading to a slight widening of the differential between light and heavy from 14 to 16 per cent. Similarly, the differential between light-medium crude oil and crude bitumen widened from 17 to 21 per cent from 2009 to 2010.

The ERCB expects the bitumen/light-medium differential to average 26 per cent over the forecast period, compared with the five-year average of 30 per cent and the 2010 average of 21 per cent. The heavy/light-medium differential is expected to average 21 per cent, narrower than the most recent five-year average of 23 per cent, but wider than the 2010 average of 16 per cent.

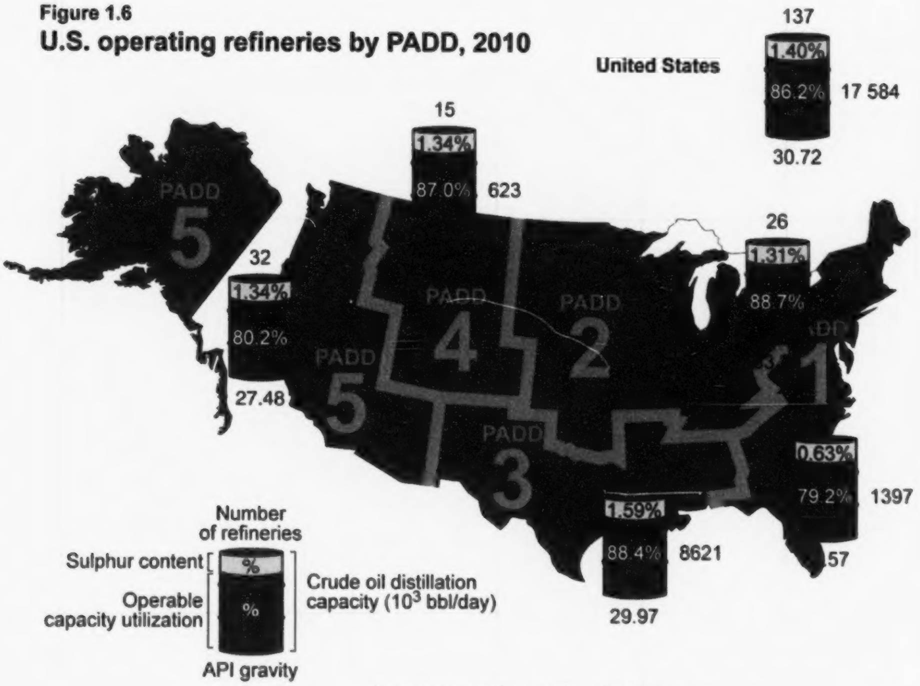
Crude oil production in Alberta, after meeting Alberta and Canadian refinery demand, is exported to the U.S. The Petroleum Administration for Defense Districts (PADDs) 2 and 4 in the U.S. are the largest importers of Alberta heavy crude and bitumen, with a combined total refinery capacity of 691 10^3 cubic metres per day (m^3/d) (4346 10^3 bbl/d). Increased heavy oil upgrading capabilities at the BP refinery at Whiting, as well as the ConocoPhillips refinery conversion project at Wood River and other refinery conversions, will increase PADD 2 and PADD 4 capacities to take on increasing amounts of Alberta's heavier crudes.

Total refinery capacity in the U.S. increased slightly during the 1990s and 2000s because of de-bottlenecking of existing refineries. No new refineries have been built since the 1970s. Before the global economic recession in 2009, product demand had increased significantly, resulting in refineries in the U.S. operating at high capacities since 1993. More recently, however, depressed refinery margins have resulted in some U.S. refineries being shut down.

Additional pipeline infrastructure is important in order to provide an avenue for increasing Alberta heavy crude exports to new or expanding markets in the U.S. and Asia. With expected increases in both upgraded and non-upgraded bitumen supply over the forecast period, adequate incremental pipeline capacity is essential to transport growing volumes to market. During the past few years, pipeline companies have made strides toward completing existing projects, as well as moving ahead with planning and construction of new projects. This has culminated in the start-up in 2010 of the TransCanada Keystone pipeline, which provides deliveries to Wood River and then to Cushing. The Enbridge Alberta Clipper project also began service in 2010. Additional pipeline projects are discussed in **Section 3.2.4**.

Figure 1.6 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the U.S., with 54 operating refineries and a net crude oil distillation capacity of 1370 10^3 m^3/d (8.6 million bbl/d). PADD 3 was not previously viewed as the most likely market for Alberta crude oil because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude production. However, traditional crude inputs to PADD 3 have been on the decline, suggesting a more tangible market opportunity for Alberta heavy crude producers. As a result, plans such as the TransCanada Keystone XL project are under way to increase pipeline capacity to the area.

Figure 1.6
U.S. operating refineries by PADD, 2010



United States
137
1.40%
86.2%
17 584
30.72
PADD 5
32
1.34%
80.2%
27.48
PADD 5
15
1.34%
87.0%
623
PADD 4
PADD 2
26
1.31%
88.7%
PADD 1
PADD 3
1.59%
88.4%
8621
29.97
0.63%
79.2%
1397
57
Number of refineries
Sulphur content
%
Operable capacity utilization
%
Crude oil distillation capacity (10^3 bbl/day)
API gravity

Source data: U.S. Energy Information Agency
Number of operating refineries as of January 1, 2010. Data for the year 2010.
Sulphur content and API gravity are weighted averages.

1.1.2.2 North American Natural Gas Prices

While North American crude oil prices have closely tracked international prices, natural gas prices are set in the North American market with little global gas market influence aside from the impact of liquid natural gas (LNG) imports. Alberta natural gas prices are heavily influenced by events in the U.S., the largest importer of Alberta natural gas. The most significant recent change in the market has been the increase in U.S. natural gas supply from shale gas—an unconventional supply source that has become economic due to horizontal drilling and multistage fracturing of the wellbore.

Figure 1.7 shows monthly data for the average Alberta natural gas price at the plant gate for 2010. As shown, prices averaged Cdn$4.88/GJ in January due to the seasonal winter impact. However, despite a rebound in U.S. natural gas demand, Canadian prices continued to decline to less than Cdn$3.00/GJ in October. The average Alberta gas price for 2010 was Cdn$3.57/GJ, compared with Cdn$3.65 for 2009, a marginal decrease of 2 per cent. Over the same period, U.S. natural gas prices increased by 10 per cent. Canadian prices were negatively affected by the appreciating Canadian dollar.

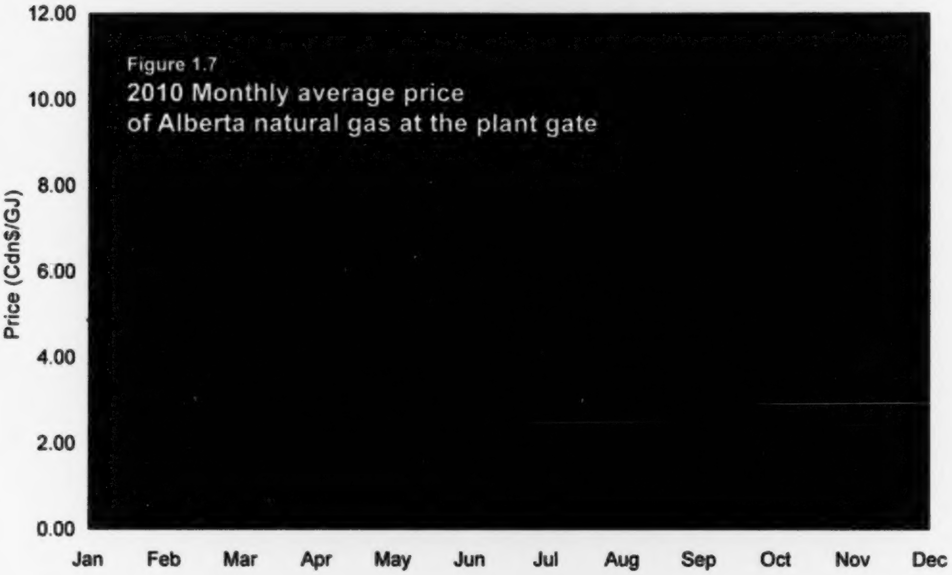


Figure 1.7
2010 Monthly average price of Alberta natural gas at the plant gate

Figure 1.8 shows the historical and forecast average price of Alberta natural gas at the plant gate. The ERCB expects natural gas prices at the Alberta wellhead to range between Cdn$3.00/GJ and Cdn$4.00/GJ in 2011, with a base price of Cdn$3.50/GJ. In the near term, prices are projected to remain weak as U.S. production of shale gas continues to offset the decline in conventional supplies. Over the forecast period, the price of natural gas is projected to increase slowly to reach an average of Cdn$7.00/GJ by 2020, while the high case could reach Cdn$8.00/GJ.

As mentioned earlier, the principal agent of change in the North American natural gas market is the emergence of shale gas, which has proved to be a major contributor to supply growth. Before the emergence of shale gas, North American conventional gas supplies were declining and projected to decline further. As a result, several liquefied natural gas (LNG) regasification facilities were built to ensure that U.S. demand could be satisfied. However, as a result of the success of shale gas production in the U.S., there are proposals to convert some regasification terminals to liquifaction terminals, and new LNG export terminals have been proposed in both the U.S. and Canada.

The U.S. has experienced substantial production increases, starting in 2006, in all areas in which shale gas drilling and production is occurring. Between 2005 and 2010, total U.S. marketed production increased by approximately 19.2 per cent, from 1.46 billion (10^9) m^3/d (51.9 billion cubic feet [Bcf]/d) in 2005 to 1.74 10^9 m^3/d (61.8 Bcf/d) in 2010.

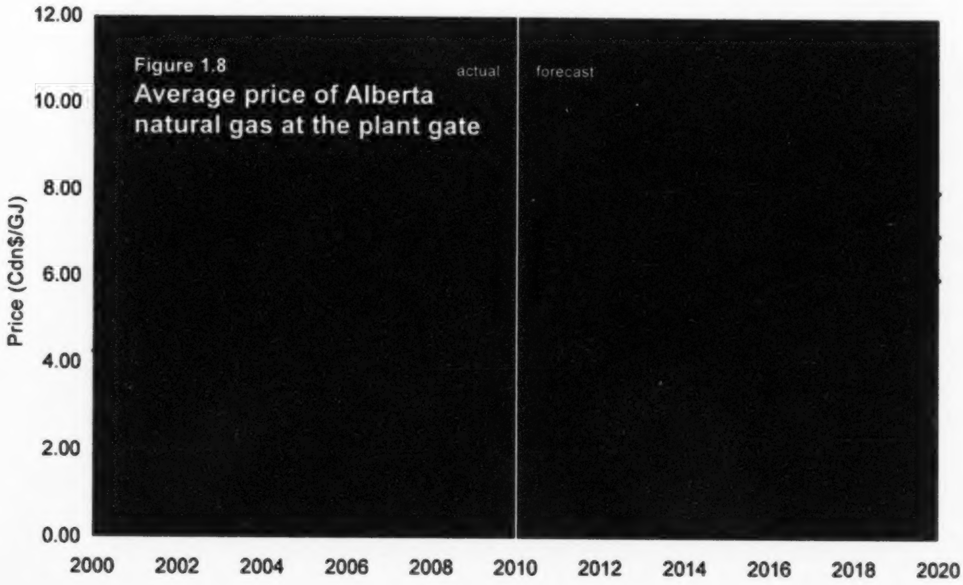


Figure 1.8
Average price of Alberta natural gas at the plant gate

The Alberta gas-to-light-medium-oil price parity on an energy content basis averaged 0.35 in 2009 and 0.29 in 2010 as natural gas prices declined and crude oil prices increased. The gas-to-oil price parity is projected to average 0.33 over the forecast period as the North American gas market remains depressed while crude oil prices continue to increase.

1.1.2.3 Electricity Pool Prices in Alberta

The electricity price paid by consumers consists of a wholesale market price determined in the power pool (pool price), transmission and distribution costs, and a fixed monthly billing charge. Since deregulation, the wholesale or pool price of electricity in Alberta has been determined by the equilibrium between electricity supply and demand.

Table 1.2 shows the average monthly pool price and electricity load in 2010. The 2009 average is included for comparison. The 2010 average pool price averaged $50.88 per megawatt-hour (MWh), compared with the 2009 average of $47.81/MWh. Monthly pool prices averaged $134.69/MWh in May 2010, reflecting the effects of coal-fired power plant outages and planned and unplanned transmission maintenance. Otherwise, monthly pool prices ranged between $28.42/MWh and $58.89/MWh, reflecting the effects of low natural gas prices and no other significant supply disruptions as in May.

The forecast for electricity supply and demand in Alberta is discussed in **Section 9**. Preliminary estimates suggest that in 2010 Alberta sectoral electricity demand increased by 1.2 per cent, similar to the last three years of growth, which averaged 0.94 per cent per year. Until 2006, the 10-year average annual growth in demand was 2.7 per cent per year.

Table 1.2 Monthly pool prices and electricity load

	Price ($/MWh)	Load (MW)		
2010	**Average**	**Average**	**Min**	**Max**
Jan	43.43	8 549	7 289	9 806
Feb	43.90	8 535	7 490	9 552
Mar	35.31	8 158	7 131	9 004
Apr	49.71	7 769	6 706	8 665
May	134.69	7 709	6 766	8 716
Jun	57.27	7 879	6 728	9 160
Jul	40.02	8 025	6 641	9 343
Aug	38.64	8 043	6 947	9 214
Sep	28.42	7 861	6 851	8 733
Oct	30.92	8 064	6 894	9 090
Nov	48.09	8 652	7 254	10 146
Dec	58.89	9 018	7 596	10 196
2010	**50.88**	**8 188**	**6 641**	**10 196**
2009	**47.81**	**7 981**	**6 454**	**10 236**

The outlook for electricity supply in the forecast period has considered the effects of two events. First, the federal government has announced a policy requiring all existing coal-fired power plants to be retired by the end of their economic lives or by the end of their power purchase agreements, whichever is the later date. Plants could only operate past those dates if stringent emission levels are met. Any new coal plants would also have to meet the same stringent emissions requirements. The new federal regulations are expected to be made official in 2011. The other factor affecting the Alberta electricity supply forecast is the stoppage of two coal fired plants. In December 2010, Sundance 1 and 2 went out of service and TransAlta subsequently declared that they would be demolished because of the cost of repairs. The forecast assumption that this capacity will not return immediately affected supply and has reduced the projection of coal-fired electrical generation.

Electricity supply growth in the forecast period will largely come from growth in natural gas-fired cogeneration facilities associated with oil sands projects and from other new natural gas-fired generation. Wind power projects are challenged because of poor economics associated with projected low natural gas prices and their effect on the electricity price outlook, and because of the lack of an attractive feed-in tariff similar to those in place in other jurisdictions. Feed-in tariffs provide for a fixed price over the project life and typically begin at a premium to current market prices.

Although average daily electricity prices in Alberta will continue to be affected by seasonal temperature influences and unplanned generating plant outages, over the long term the average annual electricity pool price will reflect Alberta natural gas prices and move higher as natural gas prices move higher.

Figure 1.9 illustrates the historical and the ERCB forecast of average annual pool prices in Alberta. Electricity prices are projected to remain in the range of prices reported from 2002 to 2008, and the forecast prices reflect the natural gas price forecast. The loss of electricity from the Sundance units increases the risk for higher prices if further unplanned outages occur.

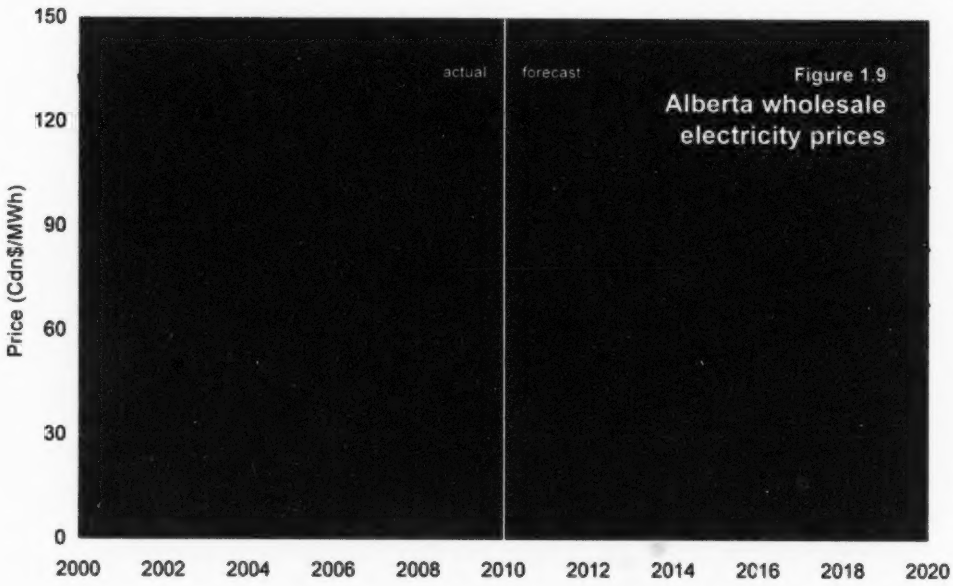


Figure 1.9
Alberta wholesale electricity prices

1.2 Oil and Gas Production Costs in Alberta

For the past 30 years, the Petroleum Services Association of Canada (PSAC) has been providing cost estimates for typical oil and gas wells for the upcoming drilling season. The cost estimates in Figure 1.10 were obtained from the 2010 and 2011 PSAC Well Cost Studies. **Table 1.3** outlines the median well depth for each area, a major factor contributing to drilling costs. Many other factors influence well costs, including the economic environment, the type of commodity produced, whether it is a development or an exploratory well, surface conditions, sweet versus sour production, drilling programs, well location, nearby infrastructure, and completion method.

Table 1.3 Alberta median well depths by PSAC area, 2010 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3 705	2 341	884	561	892	511	1 741
Oil wells	NA[a]	2 144	1 089	720	1 534	620	1 585

[a] NA—Not applicable.

As illustrated in **Figure 1.10**, the estimated cost to drill and complete a typical oil well has increased substantially from the previous year. The estimated cost of drilling and completing a typical oil well in the winter of 2010-2011 ranged from as low as $760 000 in east-central Alberta (Area 4) to as high as $2 665 000 in central Alberta (Area 5). On average, across the PSAC areas, estimates for oil well costs increased by 17.0 per cent.

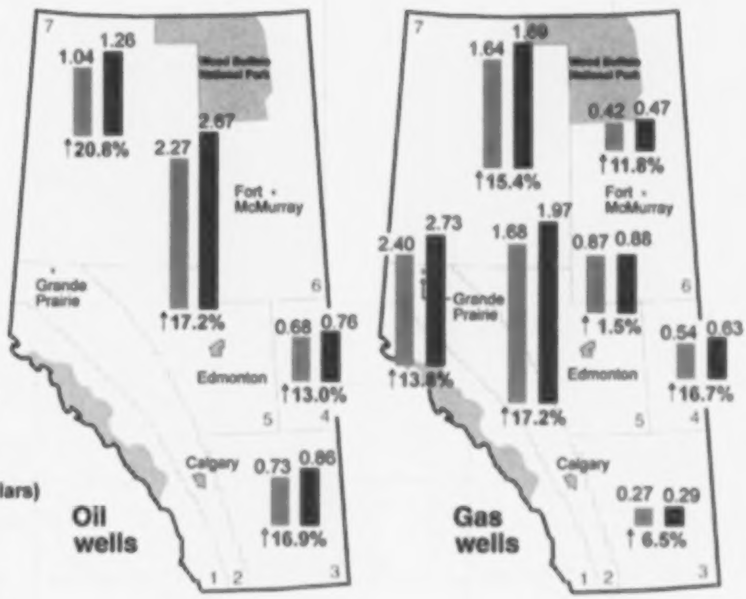

7
1.04
1.26
↑20.8%
Wood Buffalo National Park
2.27
2.67
Fort McMurray
Grande Prairie
↑17.2%
6
0.68
0.76
Edmonton
↑13.0%
5
4
Calgary
0.73
0.86
↑16.9%
Oil wells
1
2
3
7
1.64
1.89
Wood Buffalo National Park
0.42
0.47
↑11.8%
↑15.4%
Fort McMurray
2.40
2.73
1.68
1.97
0.87
0.88
Grande Prairie
6
↑ 1.5%
0.54
0.63
Edmonton
↑13.8%
↑16.7%
↑17.2%
5
4
Calgary
0.27
0.29
↑ 6.5%
Gas wells
1
2
3

Figure 1.10
Alberta well cost estimations by PSAC area
(millions of current dollars)

▨ 2009 (November)
■ 2010 (November)
% percentage change in costs

Drilling, casing, and completion cost estimates (PSAC November, 2009 and November, 2010 Well Cost Studies)

Gas well drilling and completion costs were also projected to increase. Estimated costs to drill and complete a typical gas well in the winter of 2010-2011 were highest in the Foothills (Area 1) at over $2.7 million. In Southeastern Alberta (Area 3), a typical gas well was estimated to cost about $286 000 to drill and complete. The average estimated cost to drill and complete a typical gas well across the PSAC areas increased by 11.8 per cent from the previous year.

The increase in estimated well costs for both oil and gas wells can be attributed to the significant rebound in drilling activity in the province from the depressed levels of 2009.

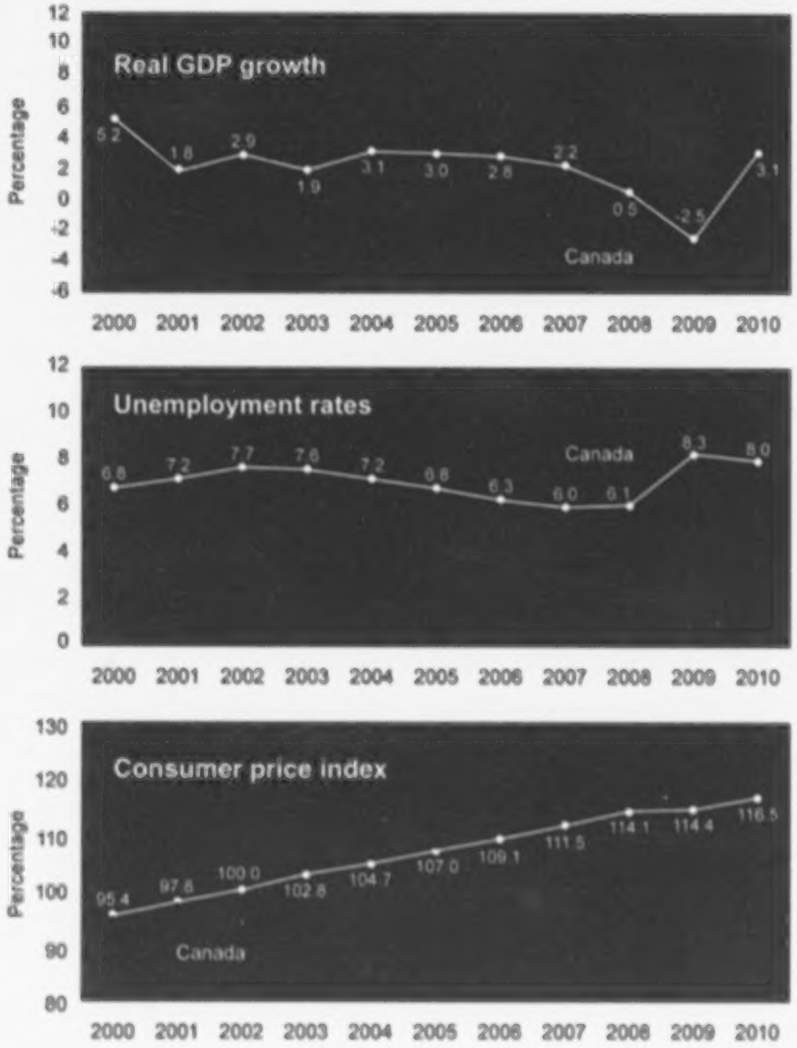
1.3 Economic Performance

1.3.1 Alberta and Canada

The historical performance of major economic indicators for Alberta and Canada between 2000 and 2010 are depicted in **Figure 1.11**.

Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly in the 2003-2007 timeframe. Average Alberta GDP growth from 2001 to 2010 was 2.5 per cent, compared with a Canadian average of 1.9 per cent. Similarly, the unemployment rate in Alberta averaged 4.7 per cent over that period, while the Canadian unemployment rate averaged 7.1 per cent.

Figure 1.11
Alberta and Canada economic indicators



Source data: Statistics Canada

The higher growth and employment levels in Alberta put pressure on the Alberta economy, which resulted in higher levels of inflation. Since 2001, inflation in Alberta has averaged 2.6 per cent per year, while Canadian inflation has averaged 2.0 per cent.

Figure 1.12 illustrates the historical performance of the US/Canadian dollar exchange rate between 2000 and 2010. The exchange rate is an economic parameter that affects both the Canadian and Alberta economies. The appreciation of the Canadian dollar over the historical period created a headwind for exporting industries.

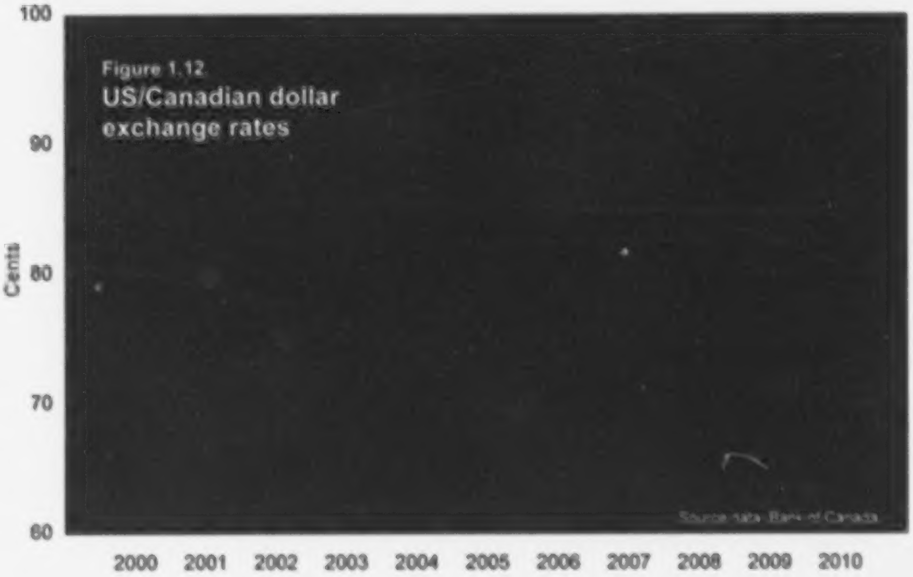


Figure 1.12
US/Canadian dollar exchange rates

Source data: Bank of Canada

The US/Canadian dollar exchange rate averaged US$0.971 in 2010, compared with US$0.876 in 2009. The exchange rate began the year averaging US$0.969 in January 2010 and averaged US$0.992 in December 2010, exhibiting relative stability as the global economy and financial system continued to recover from the financial crisis of 2008. The US/Canadian dollar exchange rate is projected to average US$1.01 in 2011, decreasing slightly to US$0.99 in 2012 and then to US$0.98 for the remainder of the forecast period.

1.3.2 The Alberta Economy in 2010 and the Economic Outlook

The ERCB forecast of Alberta real GDP and other economic indicators is shown in **Table 1.4**. Alberta real GDP is estimated to have increased by 3.3 per cent in 2010, following a decline of 4.5 per cent in 2009. Real GDP is forecast to increase by 4.3 per cent in 2011 and to continue growth at a 3.2 per cent trend from 2012 to 2020. Alberta's inflation rate increased by 1.0 per cent in 2010, trailing the national inflation rate of 1.8 per cent.

Table 1.4 Major Alberta economic indicators, 2010-2020 (%)

	2010	2011	2012-2020[a]
Real GDP growth	3.3	4.3	3.2
Population growth	1.4	1.8	2.0
Inflation rate	1.0	1.6	2.4
Unemployment rate	6.5	5.8	5.0

[a] Averaged over 2012-2020.

GDP in Alberta rebounded by 3.3 per cent in 2010, following the steep 4.5 per cent decline in 2009. Economic growth is projected to increase in 2011 as oil and gas activity recovers from the depressed levels of 2009. There were 9233 wells drilled in Alberta in 2010, compared with 6980 in 2009, an increase of 2253 wells, or 32 per cent. A revival in crude oil well drilling has played a significant role in this recovery.

The Canadian Association of Petroleum Producers (CAPP) estimates that oil sands capital expenditures increased to $13 billion in 2010 compared with $11 billion in 2009 and $18.1 billion in 2008. Construction activity for the Imperial Oil Kearl Lake project continues, and the strategic alliance announced between Suncor and Total provides greater clarity on a number of planned mined oil sands projects and upgraders. Many in situ projects have been announced and are proceeding through the application process, and projects that are further along are commencing or continuing construction.

Figure 1.13 illustrates the historical and projected profile of investment in Alberta's conventional oil and gas industry and in the oil sands industry. The forecast of capital spending is a risked profile of all announced projects and is consistent with the ERCB forecast of nonupgraded bitumen and SCO production. An unrisked capital spending profile would be significantly higher than the forecast.

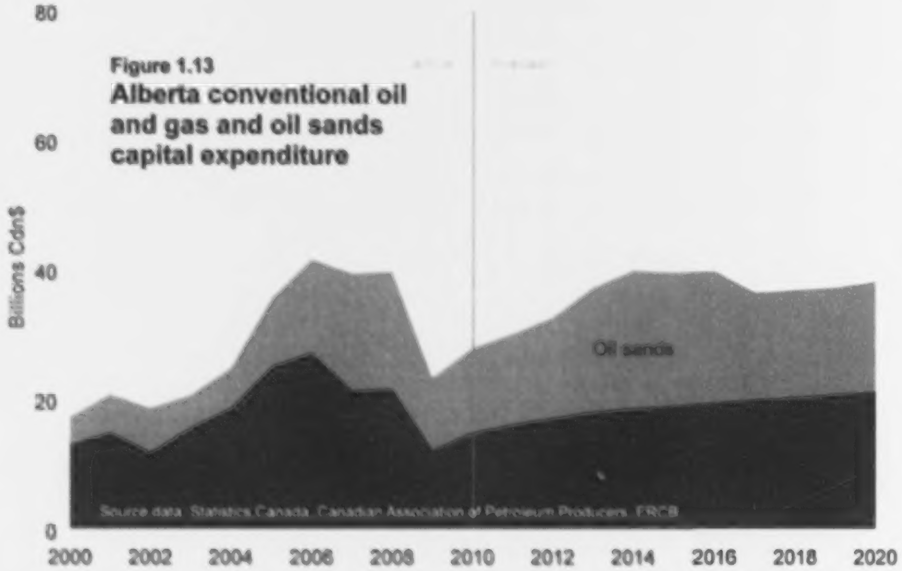


Figure 1.13
Alberta conventional oil and gas and oil sands capital expenditure

Source data: Statistics Canada, Canadian Association of Petroleum Producers, ERCB

As shown in **Figure 1.13**, oil sands related expenditures are projected to increase significantly by the middle of the decade in order to meet the forecast increases in nonupgraded bitumen and synthetic crude oil (SCO) production. Combined with a recovery in conventional oil and gas expenditures, total oil and gas investment approaches levels equivalent to the 2006-2008 peak.

During the forecast period, nonupgraded bitumen production is forecast to increase at an average annual rate of 11.9 per cent. SCO production is projected to increase at an average annual rate of 5.8 per cent. Virtually all of this production increase will be exported, providing powerful export-led economic growth for the province.

The value of Alberta's energy resource production in 2009 and 2010 is depicted in **Figure 1.14**. In 2010, the total value of production increased by 15 per cent relative to 2009. The value of SCO and bitumen production significantly exceeded the value of natural gas production for the second year, the continuation of a trend that is expected to continue throughout the forecast period. In 2010, combined SCO and bitumen revenues are approximately equal to the combined revenues from conventional gas, conventional crude oil, and natural gas liquids.

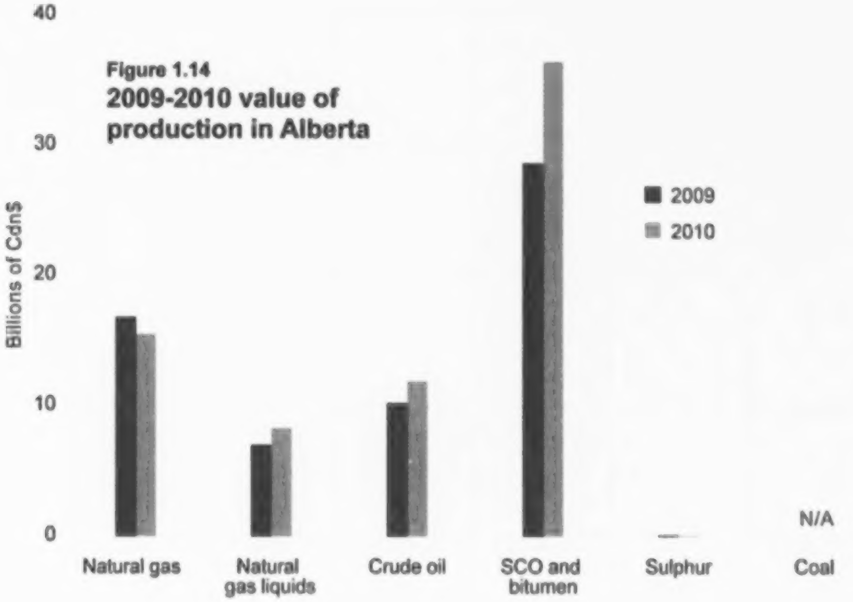


Figure 1.14
2009-2010 value of production in Alberta

The total economic value of Alberta's energy resource production for 2010 to 2020 is shown in **Table 1.5**. Production from crude bitumen and SCO derived from the oil sands will more than offset the decline in conventional resource production, increasing from 50 per cent of total revenues in 2010 to an average of 65 per cent of total revenues from 2013 to 2020.

Continued investment in mining, upgrading, and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy. Alberta's economic growth will continue to be a strong contributor to Canadian economic growth.

Table 1.5 Value of Alberta energy resource production (millions of current dollars)

	2010	2011[a]	2012[a]	2013-2020[a,b]
Conventional crude oil	11 929	15 886	18 020	17 039
Crude bitumen	14 661	20 931	22 850	40 016
Synthetic crude oil	21 700	28 203	36 502	45 615
Marketable gas	15 544	14 440	15 679	19 442
Natural gas liquids	8 298	9 875	9 947	9 301
Sulphur	141	97	103	101
Coal	n/a	n/a	n/a	n/a
Total (excludes coal)	**72 273**	**89 431**	**103 102**	**131 494**

[a] Values calculated from the ERCB's annual average price and production forecasts.

[b] Annual average over 2013-2020.

ENDOWMENT

HIGHLIGHTS

2010 introduces this new section to the report.

A discussion of the geological framework of the Western Canada Sedimentary Basin is included.

A discussion of Alberta's petroleum systems is included.

The methods the ERCB uses to estimate resources and determine reserves are given.

The reserves framework employed in the report is detailed.

2 RESOURCE ENDOWMENT

Of Alberta's many natural resources, this report focuses on energy resources, namely petroleum hydrocarbons and coal. Resource appraisal is performed by the ERCB in the fulfillment of its legislated mandate. The *Energy Resources Conservation Act* defines the activities of the ERCB. Its purposes in Section 2 include:

(a) to provide for the appraisal of the reserves and productive capacity of energy resources and energy in Alberta, and

(b) to provide for the recording and timely and useful dissemination of information regarding the energy resources of Alberta.

The resource appraisal function includes geological survey, resource estimation, and reserve determination activities at the ERCB. These activities are done in a framework that provides consistent year-to-year comparisons of energy development in Alberta. Some elements of this framework are under review to ensure that the ERCB's reserve reporting remains timely and useful, as discussed at the end of this section.

2.1 Geological Framework of Alberta

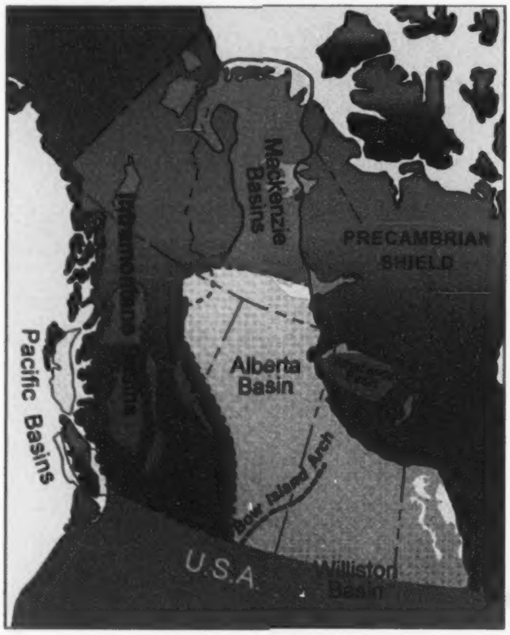
2.1.1 Western Canada Sedimentary Basin

The overall stratigraphic sequence of Alberta consists of a northeast thinning wedge of sedimentary rocks. This wedge comprises three thick packages of rock most simply described as a carbonate succession sandwiched between two clastic successions. These sedimentary strata lie overtop a crystalline basement of igneous and metamorphic rock of Precambrian age. The thickness of the sedimentary wedge tapers to zero in northeastern Alberta where the crystalline basement is exposed as part of the Canadian Shield.

The lower clastic succession is restricted to the Rocky Mountains. It is composed of thick metamorphic quartzite and slate rocks of Precambrian age and overlying sedimentary strata of Cambrian to Ordovician age. The middle carbonate succession is composed mainly of limestones, dolostones, and evaporites of Devonian to Mississippian age. The upper clastic succession is Triassic to Tertiary in age. Both the middle carbonate and the upper clastic successions cover most of Alberta. The modern land surface is a major unconformity that separates the youngest bedrock from gravels, thick glacial deposits, and modern alluvium.

The depositional trough filled in by these three thick packages is called the Western Canada Sedimentary Basin (WCSB). The WCSB is often divided into regional basinal and sub-basinal elements including the Alberta Basin, the Williston Basin, and the MacKenzie Basin, as shown on **Figure 2.1**.

Figure 2.1
Basinal elements of the Western Canada Sedimentary Basin



The geological origin and structure of Alberta's strata ultimately determine the type and extent of Alberta's energy resources. The overall geologic history of Alberta falls into two main phases:

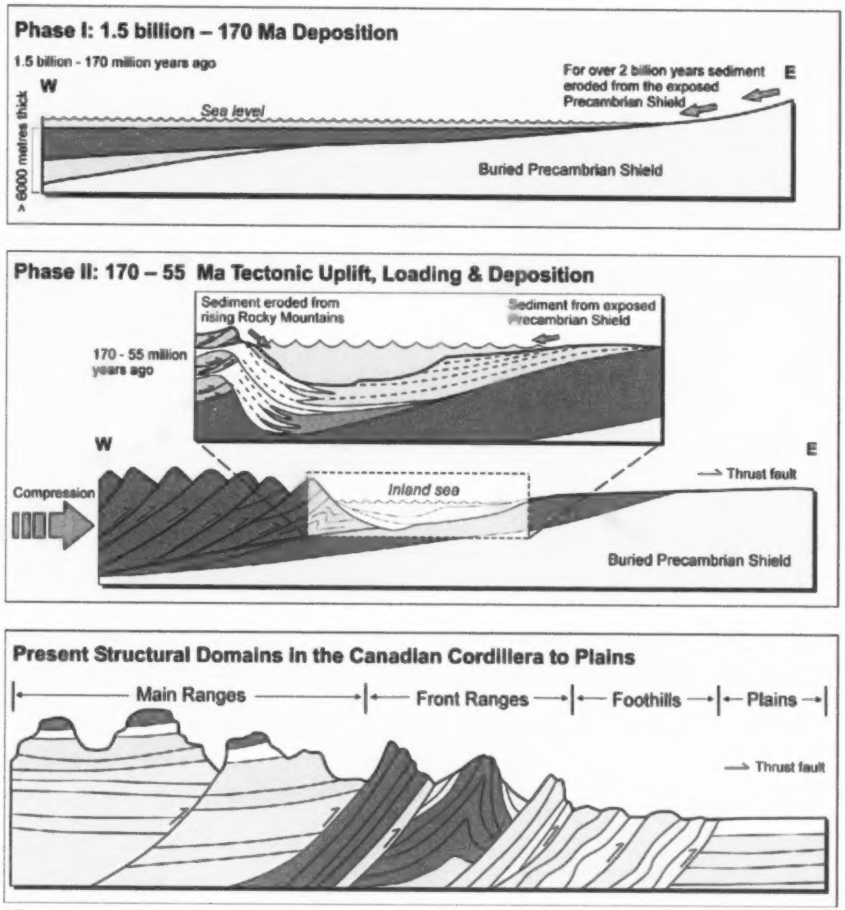
- Phase I lasted from 1.5 billion years ago to 170 million years ago. It was characterized first by deposition in a shallow sea lying along the passive continental margin of the proto-Pacific ocean. This was followed by deposition within a shallow, interior continental seaway. This seaway marked the formation of an intracratonic basin, formed indirectly in association with uplift and mountain building far to the southwest of Alberta. The lower clastic and middle carbonate successions were deposited during Phase I.

- Phase II lasted from 170 million years ago to present. It was characterized by uplift and structural deformation, which formed the Rocky Mountains and mountain ranges further west. Loading of the mountains onto the crust caused the shallow seaway of Phase I to deepen into a depositional trough called a foreland basin. Sediments from the rising mountains were shed eastward into the basin, gradually filling it in and causing the seas to retreat. Uplift abated about 55 million years ago and the

Alberta basin has undergone erosion ever since, with the exception of deposition related to glacial advances and retreats over the last two million years. The upper clastic succession was deposited during Phase II.

These events are shown in **Figure 2.2**.

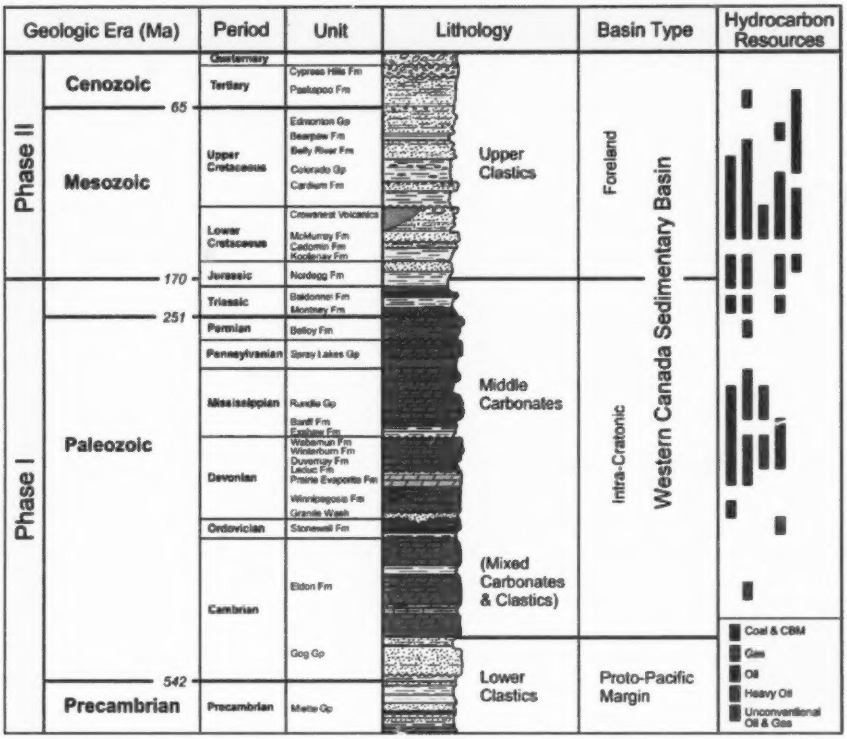
Figure 2.2
Geologic evolution of Alberta


Phase I: 1.5 billion – 170 Ma Deposition
1.5 billion - 170 million years ago
W
E
Sea level
For over 2 billion years sediment eroded from the exposed Precambrian Shield
> 6000 metres thick
Buried Precambrian Shield
Phase II: 170 – 55 Ma Tectonic Uplift, Loading & Deposition
Sediment eroded from rising Rocky Mountains
Sediment from exposed Precambrian Shield
170 - 55 million years ago
W
E
Thrust fault
Compression
Inland sea
Buried Precambrian Shield
Present Structural Domains in the Canadian Cordillera to Plains
Main Ranges
Front Ranges
Foothills
Plains
Thrust fault

* Drawings not to scale

The geological record of events in Phases I and II is preserved in the strata of the WCSB. A simplified version of Alberta's strata is shown in **Figure 2.3**. The stratigraphy is formalized in ERCB's Table of Formations. The Alberta Geological Survey of the ERCB will begin a major review of the Table of Formations in 2011 to ensure that it is fully aligned with the most recent North American Stratigraphic Code, released in 2005.

Figure 2.3
Generalized stratigraphic column of Alberta


Geologic Era (Ma)
Period
Unit
Lithology
Basin Type
Hydrocarbon Resources
Phase II
Phase I
Cenozoic
Mesozoic
Paleozoic
Precambrian
65
170
251
542
Quaternary
Tertiary
Upper Cretaceous
Lower Cretaceous
Jurassic
Triassic
Permian
Pennsylvanian
Mississippian
Devonian
Ordovician
Cambrian
Precambrian
Cypress Hills Fm
Paskapoo Fm
Edmonton Gp
Bearpaw Fm
Belly River Fm
Colorado Gp
Cardium Fm
Crowsnest Volcanics
McMurray Fm
Cadomin Fm
Kootenay Fm
Nordegg Fm
Baldonnel Fm
Montney Fm
Belloy Fm
Spray Lakes Gp
Rundle Gp
Banff Fm
Exshaw Fm
Wabamun Fm
Winterburn Fm
Duvernay Fm
Leduc Fm
Prairie Evaporite Fm
Winnipegosis Fm
Granite Wash
Stonewall Fm
Eldon Fm
Gog Gp
Miette Gp
Upper Clastics
Middle Carbonates
(Mixed Carbonates & Clastics)
Lower Clastics
Foreland
Intra-Cratonic
Western Canada Sedimentary Basin
Proto-Pacific Margin
Coal & CBM
Gas
Oil
Heavy Oil
Unconventional Oil & Gas

2.1.2 Alberta's Petroleum Systems

Petroleum is a naturally occurring organic mixture consisting predominantly of chain and ring molecules of carbon and hydrogen with varying amounts of sulphur, nitrogen, and oxygen as impurities. Petroleum forms underground by the action of heat and pressure over millions of years on buried organic matter that originated as dead algal, plankton, and plant remains. Rock units sufficiently rich in organic matter to generate petroleum during burial are called source rocks. After petroleum generation begins, the petroleum is driven from the source rock and migrates along permeable strata and fractures until it is trapped by favourable geological configurations of low-permeability rock or escapes to surface. Not all of the petroleum generated in source rocks will migrate; much is left within the source beds themselves. Coal beds are a special type of source rock in which the organic material content is well over 50 per cent of total rock mass. Coal beds can produce substantial amounts of methane.

The linked assemblage of source rock, migration routes, and ultimate traps is called a petroleum system. The Alberta Basin component of the WCSB contains at least eight petroleum systems associated with the following major source rocks:

- Middle Devonian System—sourced by basinal marine laminites of the Keg River/ Winnipegosis formations.
- Upper Devonian System—sourced by basinal marine laminites of the Leduc-equivalent Duvernay and Cooking Lake-equivalent Majeau Lake formations.
- Upper Devonian System—sourced by basinal laminites of the Cynthia Member of the Nisku Group.
- Uppermost Devonian and lowermost Mississippian System—sourced by the basin-wide marine mudstones of the Exshaw Formation.
- Middle Triassic System—sourced by the marine phosphatic siltstones at the base of the Doig Formation.
- Lower Jurassic System—sourced by the marine lime muds of the Nordegg (Gordondale) Member of the Fernie Group.
- Lower Cretaceous System—sourced by the continental coals and carbonaceous shales of the Mannville Group.
- Upper Cretaceous System—sourced by the marine mudstones of the Colorado Group, principally the First and Second White Speckled Shales and the Fish Scales Zone.

The Exshaw, Nordegg, and Duvernay source rocks are thought to have supplied most of the hydrocarbons in the Alberta Basin.

Conventional oil and gas pools are found throughout the middle carbonate and upper clastic successions. Little oil and gas is known to occur in the lower clastic succession, and the crystalline basement has none. Coals and coalbed methane (CBM) are found within the Jurassic, Cretaceous, and Tertiary-age portions of the upper clastic succession. Heavy oil and bitumen occur mostly in Cretaceous-age strata at the shallow, updip edge of the Alberta Basin, near the contact of the sedimentary successions with the underlying crystalline rocks of the Precambrian basement. There is also bitumen in the middle carbonate succession directly underneath.

In addition to these deposits, there is widespread biogenic generation of methane in the shallow subsurface, mostly in unconsolidated glacial deposits and shallow, coal-bearing bedrock units. This gas is pervasive but does not occur in commercial quantities and sometimes is a geological hazard in shallow water wells in Alberta.

2.1.3 Energy Resource Occurrences—Plays, Deposits, and Pools

Estimates of potential volumes of hydrocarbon generation and migration can be quantified for petroleum systems through detailed basin analysis. Petroleum-system analyses are not generally performed at scales applicable to issues of resource-conservation and industry regulation. Instead, each petroleum system can be subdivided into geological plays.

A geological play can be defined as a set of known or postulated oil and/or gas accumulations (pools and deposits) within a petroleum system sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. The geographic limit of each play represents the limits of the geologic elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour gas play.

It is common practice for industry to categorize exploration and development opportunities in terms of geological plays. The ERCB does not currently designate or otherwise formally declare geological plays. The ERCB does designate oil sands areas, coal fields, oil and gas fields, and strike areas. These constructs were originally congruous with geological plays but devolved into administrative entities as more geological plays became recognized within and across their boundaries.

Starting in 2011, the ERCB will be assembling a catalogue of geological plays in Alberta from various past studies and summarizing Alberta's energy resources and reserves in a geological-play context.

2.2 Resource Appraisal Methodologies

The ERCB uses the term resource appraisal to encompass all aspects of quantifying Alberta's in-place resources and recoverable reserves. To add clarity to the major components of resource appraisal, beginning with this report, the ERCB will use the phrase resource estimation to describe activities related to quantifying the amount of energy resources in the ground, and the phrase reserves determination to describe activities related to quantifying the recoverable portion of these in-place resources (i.e., the established reserves).

2.2.1 Resource Estimation

The ERCB generates its own resource estimates. The in-place resources estimation process starts with the receipt by the ERCB of raw data submitted by energy resource industries, either as required by legislation or through regulatory applications or submissions, the vast majority of which is well or borehole data. ERCB geological staff use pertinent data such as geophysical well logs, cores and drill cuttings, core analysis, and well test data (such as pressure) together with industry or academic information such as reports, seismic data, or regional studies to estimate petrophysical information and various geological surfaces and zones. These geological and petrophysical evaluations are used for both regulatory and resource appraisal purposes. Several techniques, including geostatistics, are used in generating a volumetric estimate of in-place resources for the various energy resources. As the ERCB's play catalogue is compiled, resource estimates for each play will be reported.

2.2.2 Reserves Determination

The ERCB determines two types of estimates of the recoverable portion of Alberta's in-place-resources. The portion determined recoverable from known accumulations or deposits using today's technology is classified as established reserves. The portion determined from known and unknown resources using reasonably foreseeable technology is classified as the ultimate potential. Established reserves are determined on an ongoing basis, whereas ultimate potentials usually result from major studies conducted periodically. These terms are defined in a following section.

In determining the established reserves of an energy resource, consideration is given to geology, pressures, production, technology, and economics. Geological factors are mainly considered when estimating in-place quantities. However, additional considerations are usually required to reduce the in-place quantity to a more likely developable quantity and to assure the existence and extent of the recoverable portion.

Alberta's production of oil and gas has predominantly come from conventional pools in which hydrocarbons have accumulated in concentrated quantities in porous and permeable reservoirs drainable by vertical wells. The ERCB determines reserves of conventional pools through accepted practice of geology-based volumetric estimation, production decline-analysis, and material balance methodology.

Initially there is a higher level of uncertainty in the reserves estimates, but this level decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. Analysis of production decline data is a primary method of determining recoverable reserves. It also provides a realistic estimation of the pool's recovery efficiency when it is combined with a volumetric or a material balance estimate of the in-place resource.

The determination of reserves in deposits is similar to the methods used to determine pool reserves. One or more factors are applied against an in-place volume or tonnage to determine the recoverable portion of the resource. These reserves are often estimated by three-dimensional geological models that routinely involve the data from hundreds or thousands of boreholes, both wells and drillholes.

2.2.3 Ultimate Potential

Ultimate potential numbers represent recoverable quantities. They are determinations done on a provincial basis and at a future end of the day timescale. These estimates are the result of considering all development of an energy resource up to the time of the estimate and looking forward to cessation of exploration activity and the type of technology that might reasonably be expected to be used in the future. Future-based economic circumstances are also considered. The goal of these estimates is to supply a reasonable look forward so that production forecasts and government policy decisions can be made with a credible look forward for energy resources.

2.3 Resources and Reserves Classification System

The ERCB reports the reserves of Alberta by commodity (crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal) based on the Inter-Provincial Advisory Committee on Energy (IPACE) system for uniform terminology and definitions in the estimating and publishing of hydrocarbon reserves information in Canada. The IPACE system was adopted by most government and national bodies for the use of reserves reporting in Canada in 1978 and has been in use since that time. The IPACE system was designed as a simple categorization of reserves to facilitate understanding and transparency in reporting to the public. The key reserves definitions in the IPACE system are:

> Initial volume in-place—the gross volume of crude oil, crude bitumen, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.
>
> Established reserves—those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus that judgment portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
>
> Initial established reserves—established reserves prior to the deduction of any production.
>
> Remaining established reserves—initial established reserves less cumulative production.
>
> Ultimate potential—an estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools.

The IPACE system was designed, and is most appropriate, for use with conventional oil and gas resources. Consequently, the ERCB has introduced alterations to the IPACE system to make it compatible for all energy resources, including coal. Alterations have also been applied to unconventional resources such as crude bitumen to more fully report the resource endowment of Alberta.

Unlike conventional resources, for which the lead time between successful exploration and development is relatively short, resources developed by mines (coal and mineable oil sands) often require long lead times. As a result, much exploration information can become available without the requisite increase in the number of mines. Such a condition existed in the late 1970s and early 1980s in Alberta. One of the ERCB's first IPACE alterations was the publication of separate estimates for those coal and mineable oil sands resources that were determined to be recoverable on a province-wide basis and those determined only from areas being actively mined ("established reserves under active development"). For the estimates on a provincial basis, a recoverable portion was determined (i.e., established reserves) only from areas with sufficient data and assuming proven mining technology, generalized industry economic scenarios, and the existence of adequate markets when required.

The ERCB adopted a similar approach for in situ crude bitumen reserves. In this case, however, because new technologies were being used, the ERCB began publishing provincial established reserves based on active development areas only. As confidence in the technologies grew, the ERCB decided to produce, for year-end 1999, a much larger provincial estimate in addition to the active development estimate. This approach helped reflect the true size of the in situ bitumen resource that could be developed using existing technologies.

The ERCB's approach to determining CBM reserves also follows the approach taken for in situ crude bitumen. CBM reserves are generally restricted to areas of active development. The ERCB believes that moving to a more province-wide determination is not yet appropriate, but may be in the future.

For unconventional hydrocarbon resources and coal, another significant change from IPACE is the differentiation between the total amount of in-place resource and the more developable portion that recovery operations might reasonably be expected to target. An example of the determination of this developable in-place quantity is detailed in Section 3.1.3, where it is classified as the "initial mineable volume in place" of crude bitumen.

Since 1978, and particularly since 1997, the mineral and petroleum industries have strived for tighter definitions of reserves to better suit the financial markets. These efforts include the promulgation of National Instrument 51-101, in 2003, for petroleum reserve reporting to Canadian securities regulators, the creation of and updates to the Canadian Oil and Gas Evaluation Handbook (COGEH), the Petroleum Resources Management System (PRMS),[1] and the United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009 (UNFC-2009). These efforts are under review by the ERCB and a decision to either maintain or modify the IPACE system or adopt one of these newer frameworks will be considered in the future by the ERCB.

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[1] The PRMS was prepared by the Society of Petroleum Engineers and reviewed and jointly sponsored by the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers.

3 CRUDE BITUMEN

HIGHLIGHTS

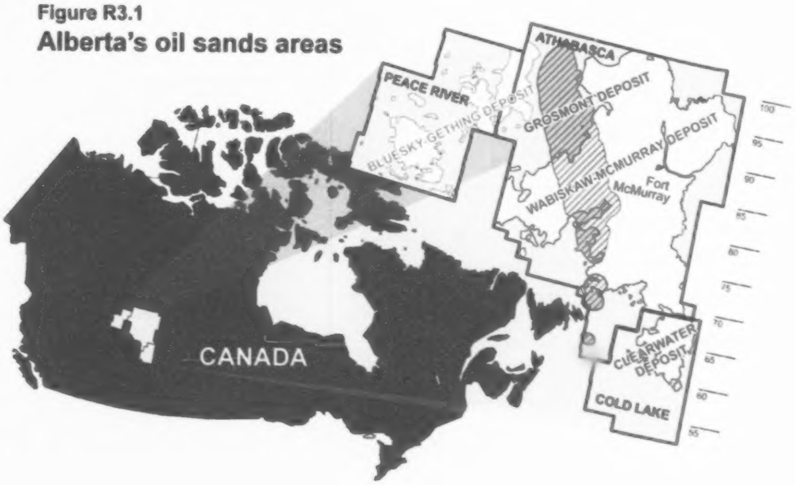
Total bitumen production increased by 8 per cent; mineable production increased by 4 per cent, and in situ production increased by 14 per cent.

Synthetic crude oil production increased by 4 per cent.

Crude bitumen is extra heavy oil that in its natural state does not flow to a well. It occurs in sand (clastic) and carbonate formations in northern Alberta. The crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands. For administrative purposes the geologic formations and the geographic area containing the bitumen are designated as oil sands areas (OSAs). Other heavy oil is deemed to be oil sands if it is located within an OSA. Since some bitumen within an OSA will flow to a well, it is amenable to primary development and is considered to be primary crude bitumen in this report.

The three designated OSAs in Alberta are shown in **Figure R3.1**. Together they occupy an area of about 142 000 square kilometres (km^2) (54 000 square miles). Contained within the OSAs are 15 oil sands deposits that designate the specific geological zones containing the oil sands. The known extent of the two largest deposits, the Athabasca Wabiskaw-McMurray and the Athabasca Grosmont, as well as the Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are also shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 km (30 miles) apart.

Figure R3.1
Alberta's oil sands areas



Two methods are used for recovery of bitumen, depending on the depth of the deposit. North of Fort McMurray, crude bitumen occurs near the surface and is recovered by open pit mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is extracted from the mined material in large facilities using hot water. At greater depths, the bitumen is recovered in situ. In situ recovery takes place both by primary development, similar to conventional crude oil production, and by enhanced development whereby generally the reservoir is heated to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal wellbore. The vast majority of lands thought to contain bitumen developable by either method are currently leased.

3.1 Reserves of Crude Bitumen

3.1.1 Provincial Summary

The ERCB continually updates Alberta's crude bitumen resources and reserves on both a project and deposit basis. While no updated results are available for this year's publication both the Athabasca Grand Rapids and Nisku deposits will be reported on in a future report.

No significant changes were made to the in-place resource or the estimate of the initial established reserves of crude bitumen in 2010. The remaining established reserves at December 31, 2010, are 26.90 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to production of 0.094 10^9 m^3.

Of the total 26.90 10^9 m^3 remaining established reserves, 21.51 10^9 m^3, or about 80 per cent, is considered recoverable by in situ methods while the remaining 5.39 10^9 m^3 is recoverable by surface mining methods. Of the in situ and mineable totals, 4.13 10^9 m^3 is within active development areas. **Table 3.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

Table 3.1 In-place volumes and established reserves of crude bitumen (10^9 m^3)

Recovery method	Initial volume in place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	20.8	6.16	0.77	5.39	3.64
In situ	265.8	21.94	0.43	21.51	0.49
Total	**286.6**	**28.09**[a]	**1.19**	**26.90**[a]	**4.13**
	(1 804)[b]	(176.8)[b]	(7.5)[b]	(169.3)[b]	(26.0)[b]

[a] Any discrepancies are due to rounding.

[b] Imperial equivalent in billions of barrels.

The changes, in million cubic metres (10^6 m^3), of initial and remaining established crude bitumen reserves and cumulative and annual production for 2010 are shown in **Table 3.2.** Crude bitumen production in 2010 totalled 93.5 10^6 m^3, with 43.8 10^6 m^3 from in situ operations.

The remaining established reserves from active development areas are presented in **Figure R3.2**. These project reserves have a stair-step configuration representing start-up of new large mining projects. The intervening years between additions are characterized by a slow decline due to annual production.

Table 3.2 Reserve and production change highlights (10^6 m^3)

	2010	2009	Change[a]
Initial established reserves			
Mineable	6 157	6 157	0
In situ	21 935	21 935	0
Total[a]	**28 092**	**28 092**	**0**
	(176 780)[b]	(176 780)[b]	
Cumulative production			
Mineable	768	718	+50[c]
In situ	426	382	+44[c]
Total[a]	**1 194**	**1 099**	**+95[c]**
Remaining established reserves			
Mineable	5 389	5 439	-50
In situ	21 509	21 554	-45
Total[a]	**26 898**	**26 992**	**-94**
	(169 267)[b]	(169 858)[b]	
Annual production			
Mineable	50	48	+2
In situ	44	39	+5
Total[a]	**94**	**86**	**+7**

[a] Any discrepancies are due to rounding.

[b] Imperial equivalent in millions of barrels.

[c] Change in cumulative production is a combination of annual production and all adjustments to previous production records.

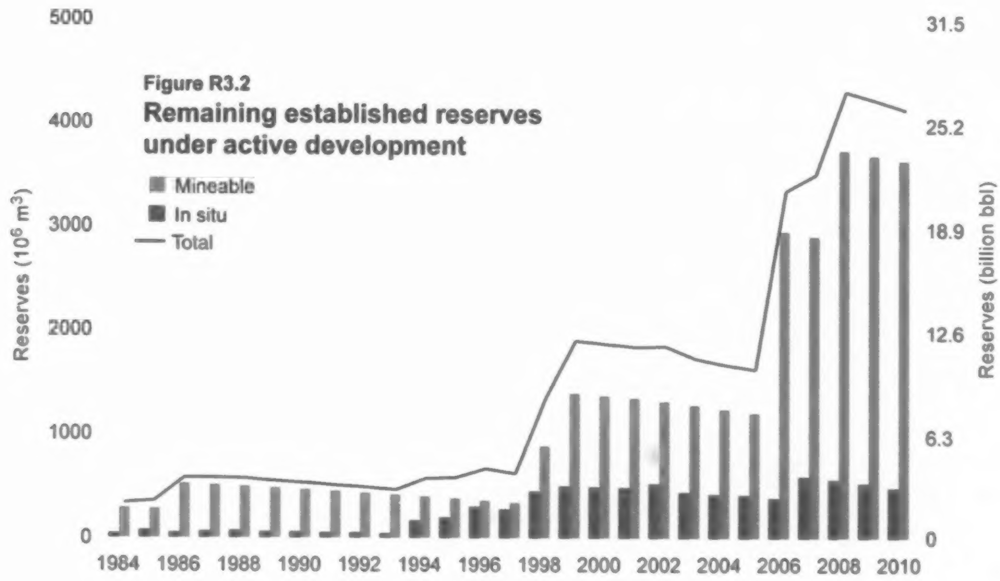


Figure R3.2
Remaining established reserves under active development

3.1.2 Initial In-Place Volumes of Crude Bitumen

Efforts to update the province's crude bitumen resources and reserves began in 2003, and since then 7 of the 15 deposits have been updated. The largest deposit, the Athabasca Wabiskaw-McMurray, was updated for year-end 2004, and subsequently revised in 2009 to take new drilling into account. The Athabasca Wabiskaw-McMurray has the largest cumulative and annual production. The Cold Lake Clearwater deposit has the second largest production and was updated for year-end 2005, as was the northern portion of the Cold Lake Wabiskaw-McMurray deposit. The Peace River Bluesky-Gething deposit was updated for year-end 2006.

In 2009, the ERCB completed a major review of the Cold Lake Upper and Lower Grand Rapids deposits and the Athabasca Grosmont deposit. Bitumen pay thickness maps for these deposits are presented in **Appendix E**. Also included in **Appendix E** are two structure contour maps for the sub-Cretaceous unconformity, one a regional map covering the entire oil sands areas, and a second map that provides detail in the Cold Lake OSA. In 2010, work commenced on updating the Athabasca Upper, Middle and Lower Grand Rapids deposits as well as the Athabasca Nisku Deposit. Results of these studies will be presented in a future report. Recently, industry has been actively exploring the Leduc Formation for potential bitumen resources west of Fort McMurray. Preliminary results indicate bitumen pay thicknesses exceed 100 metres (m) in some cases. The ERCB anticipates administratively defining a bitumen deposit for the Leduc in the near future.

The quality of an oil sands deposit depends primarily on the degree of saturation of bitumen within the reservoir and the thickness of the saturated interval. The level of bitumen saturation within a reservoir can vary considerably, decreasing as the shale or clay content within the reservoir increases, or as the porosity decreases. A greater volume of water within the pore space of the rock also decreases bitumen saturation. Bitumen saturation is expressed as mass per cent in sands (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water) and per cent pore volume in carbonates (the percentage of the volume of pore space that contains bitumen). The selection of appropriate saturation and thickness cutoffs for determining resources and reserves varies, depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.

Initial in-place volumes of crude bitumen in each deposit were determined using drillhole data, including geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 m for in situ areas. As of year-end 1999, the saturation cutoff was increased to 6 mass per cent for areas amenable to surface mining. In the six previous reports, the Athabasca Wabiskaw-McMurray, Cold Lake Clearwater, the Peace River Bluesky-Gething, and Cold Lake Grand Rapids deposits, as well as a portion of the Cold Lake Wabiskaw-McMurray deposit, were also estimated using a 6 mass per cent saturation cutoff.

The crude bitumen within the carbonate deposits was originally determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent. In the 2009 revision of the Athabasca Grosmont, a pore volume of 50 per cent and a porosity of 8 per cent were chosen as more appropriate cutoff values.

The ERCB believes that in measuring the quality of an oil sands area, cutoffs of 6 mass per cent for clastic bitumen deposits, and a pore volume of 50 per cent and porosity of 8 per cent for carbonate bitumen deposits, more accurately reflect the volumes from which bitumen can reasonably be expected to be recovered.

Within the Athabasca OSA is the ERCB-defined surface mineable area (SMA). It encompasses an area of 51½ townships north of Fort McMurray, covering the part of the Athabasca Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. As a result of the lower overburden thickness, it is presumed that the main recovery method will be surface mining, unlike in the rest of Alberta's crude bitumen area where in situ technology is the only presently viable recovery mechanism. However, the defined boundaries of the SMA are simply for resource administration purposes and carry no regulatory authority. While the ERCB has estimated mineable reserves from unmined areas within the SMA for provincial resource assessment purposes, surface mining may not actually take place, possibly reducing the estimate of mineable reserves. Within the SMA, just under 50 per cent of the initial mineable bitumen in-place resource occurs at a depth of less than 25 m of overburden.

Since the boundaries of the SMA are defined using the boundaries of townships, a few areas of deeper bitumen resources more amenable to in situ recovery are included. As a result, while the extent of the SMA covers both mineable and in situ resources, estimates of mineable bitumen exclude those volumes within the SMA that are beyond mineable depths. Conversely, in situ estimates include all areas outside the SMA and those deeper areas, generally greater than 65 m, within the SMA.

The crude bitumen resource volumes and basic reservoir data are presented on a deposit basis in **Tables B.1** and **B.2** respectively in **Appendix B** and are summarized by formation in **Table 3.3**.

The in-place resource values in **Table 3.3** represent the total crude bitumen accumulated throughout the deposit, where the cumulative thickness is equal to or greater than 1.5 m; however, current and anticipated recovery operations often only develop the better portion of this total. This developable portion (also known as mineable, exploitable, or SAGDable[1]) varies depending on the type of recovery technology employed. Recovery factors are normally applied against this developable portion to determine the established reserves. The parameters used to reduce the total in place volumes to a developable subset are given in Section 3.1.3.

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[1] SAGD—steam assisted gravity drainage.

Table 3.3 Initial in-place volumes of crude bitumen as of December 31, 2010

				Average bitumen saturation		
Oil sands area **Oil sands deposit**	**Initial volume in place ($10^6 m^3$)**	**Area (10^3 ha*)**	**Average pay thickness (m)**	**Mass (%)**	**Pore volume (%)**	**Average porosity (%)**
Athabasca						
Grand Rapids	8 678	527	9.6	6.5	57	30
Wabiskaw-McMurray (mineable)	20 823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131 609	4 694	13.1	10.2	73	29
Nisku	10 330	499	8.0	5.7	63	21
Grosmont	64 537	1 766	23.8	6.6	79	20
Subtotal	**235 977**					
Cold Lake						
Upper Grand Rapids	5 377	612	4.8	9.0	65	28
Lower Grand Rapids	10 004	658	7.8	9.2	65	30
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.1	8.1	62	28
Subtotal	**29 090**					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	**21 560**					
Total	**286 627**					

*ha—hectare

3.1.3 Established Reserves

There are two major types of established reserves of crude bitumen. Mineable reserves are those established reserves that are anticipated to be recovered by surface mining operations. In situ reserves are those established reserves that are anticipated to be recovered through wells by one of several in situ recovery methods.

3.1.3.1 Surface-Mineable Crude Bitumen Reserves

With the 2008 expansion of the SMA and the subsequent updating of the Athabasca Wabiskaw-McMurray deposit, the only oil sands deposit in the SMA, the ERCB now estimates that the SMA contains 20.8 10^9 m^3 of initial bitumen in-place resource at depths most suitable to mineable technologies, generally less than 65 m. For year-end 2008, potential mineable areas in the total in-place portion of the SMA were identified using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 mass per cent bitumen, and a minimum saturated interval thickness cutoff of 3.0 m. The ESR criteria are fully explained in Appendix III of *ERCB Report 79-H: Alsands Fort McMurray Project*. As of December 31, 2008, this method reduced the initial volume in place of 20.8$10^9$ m^3 to 10.3 10^9 m^3. This latter volume is classified as the initial mineable volume in place.

Factors were applied to the initial mineable volume in place to determine the established reserves. A series of reduction factors was applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total volume; therefore, each factor is set at 90 per cent. A combined mining and extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by mining operations and extraction facilities. The resulting initial established reserves of crude bitumen is 6.16 10^9 m^3. As of December 31, 2010, the remaining established mineable crude bitumen reserves has decreased from 5.44 10^9 m^3 to 5.39 10^9 m^3 as a result of production.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2010, are presented in **Table 3.4**. At the end of 2010, almost three quarters of the initial established reserves were under active development. Currently, Canadian Natural Resources Limited (CNRL Horizon), Shell Canada Limited (Shell Albian Sands and Shell Jackpine), Suncor Energy Inc. (Suncor), and Syncrude Canada Ltd. (Syncrude), are the only producers in the SMA, with a combined cumulative bitumen production of 768 10^6 m^3. While the Fort Hills mine project (owned by Suncor, TOTAL E&P Canada Ltd., and Teck Resources Ltd.), and the Imperial Oil/ ExxonMobil Kearl project are not yet producing bitumen they are considered to be under active development and are included in **Table 3.4**.

Table 3.4 Mineable crude bitumen reserves in areas under active development as of December 31, 2010

Development	Project area[a] (ha)	Initial mineable volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)
CNRL Horizon	28 482	834	537	10	527
Fort Hills	18 976	699	364	0	364
Imperial/Exxon Kearl	19 674	1 324	872	0	872
Shell Albian Sands	13 581	672	419	63	356
Shell Jackpine	7 958	361	222	2	220
Suncor	19 155	990	687	283	404
Syncrude	44 037	2 071	1 306	410	896
Total	**151 863**	**6 951**	**4 407**	**768**	**3 639**

[a] The project areas correspond to the areas defined in the project approval.

Production from the five current surface mining operations amounted to 49.7 10^6 m^3 in 2010, with 20.3 10^6 m^3 from the Syncrude project, 15.4 10^6 m^3 from the Suncor project, 6.2 10^6 m^3 from the Shell Albian Sands project, 1.5 10^6 m^6 from the Shell Jackpine project, and 6.3 10^6 m^3 from the CNRL Horizon project.

3.1.3.2 In Situ Crude Bitumen Reserves

The ERCB has determined an in situ initial established reserve for those areas considered amenable to in situ recovery methods. Reserves are estimated using cutoffs appropriate to the type of development and differences in reservoir characteristics. Areas amenable to thermal development were determined using a minimum zone thickness of 10.0 m in all deposits with commercial development. For deposits with primary development, a minimum zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. While some reserves estimates have been updated using a minimum saturation cutoff of 6 mass per cent bitumen, much of the current data is still based on the 3 mass per cent bitumen cutoff for most deposits. Future reserves estimates will be based on values higher than 3 mass per cent.

Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to areas that met the cutoffs. The deposit-wide recovery factor for thermal development is lower than some of the active project recovery factors to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer quality resource areas. These overall recovery factors are currently under review.

While the volume of the in-place crude bitumen in the Athabasca Grosmont deposit was reassessed in 2009, no reserves were estimated as there are no commercial projects currently operating in the Grosmont. While exploration has occurred and different recovery methods have been experimented with, commercial operations have yet to be established. The ERCB estimates reserves only in deposits where commercial operations are in place.

In 2010, the in situ bitumen produced was 43.8 10^6 m^3, an increase from 38.5 10^6 m^3 in 2009. Cumulative production within in situ areas now totals[2] 425.1 10^6 m^3, of which 297.7 10^6 m^3 is from the Cold Lake OSA. The remaining established reserves of crude bitumen from in situ areas decreased from 21.55 10^9 m^3 in 2009 to 21.51 10^9 m^3 in 2010, due to production of 0.044 10^9 m^3.

The ERCB's 2010 estimate of the established in situ crude bitumen reserves under active development is shown in **Table 3.5**. Information on experimental schemes has been removed from the table due to the limited number of experimental schemes and the confidential nature of the associated production data.

The ERCB has assigned initial volumes in place and initial and remaining established reserves for commercial projects and primary recovery schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is also shown for all commercial and primary recovery schemes within a given oil sands deposit and area. In a future edition of this report, large thermal projects and primary schemes will be listed individually, similar to **Table 3.4**. The initial established reserves under

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[2] This does not include some 7 10^6 m^3 produced from active and terminated experimental schemes.

Table 3.5 In situ crude bitumen reserves[a] in areas under active development as of December 31, 2010

Development	Initial volume in place (10^6 m^3)	Recovery factor (%)	Initial established reserves (10^6 m^3)	Cumulative production[b] (10^6 m^3)	Remaining established reserves (10^6 m^3)
Peace River Oil Sands Area					
Thermal commercial projects	55.8	40	22.3	10.8	11.5
Primary recovery schemes	160.8	10	16.1	10.2	5.9
Subtotal[c]	**216.6**		**38.4**	**21.0**	**17.4**
Athabasca Oil Sands Area					
Thermal commercial projects	313.7	50	156.9	68.0	88.9
Primary recovery schemes	1 026.2	5	51.3	22.5	28.8
Enhanced recovery schemes[d]	(289.0)[e]	10	28.9	15.9	13.0
Subtotal[c]	**1 339.9**		**237.1**	**106.4**	**130.7**
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[f]	1 212.8	25	303.2	211.5	91.7
Thermal commercial (SAGD)[g]	33.8	50	16.9	1.9	15.0
Primary recovery schemes	6 257.5	5	313.0	84.3	228.7
Subtotal[c]	**7 504.1**		**633.0**	**297.7**	**335.4**
Total[c]	**9 060.7**		**908.5**	**425.1**	**483.5**

[a] Thermal reserves reported in this table are assigned only for lands on which thermal recovery is approved and drilling development has occurred.

[b] Cumulative production to December 31, 2010, includes amendments to production reports.

[c] Any discrepancies are due to rounding.

[d] Schemes currently on polymer or waterflood in the Brintnell-Pelican area. Previous primary production is included under primary schemes.

[e] The in-place number is that part of the primary number above that will see incremental production due to polymer or waterflooding.

[f] Cyclic steam simulation projects.

[g] Steam-assisted gravity drainage projects.

primary development are based on a 5 per cent average recovery factor. The recovery factors of 40, 50, and 25 per cent for thermal commercial projects in the Peace River, Athabasca, and Cold Lake areas respectively reflect the application of various steaming strategies and project designs.

That part of the total remaining established reserves of crude bitumen from within active in situ project areas is estimated to be 483.5 10^6 m^3, a slight decrease from 2009 due to 2010 production.

3.1.4 Ultimate Potential of Crude Bitumen

The ultimate potential of crude bitumen recoverable by in situ recovery methods is estimated to be 33 10^9 m^3 from Cretaceous clastic sediments and 6 10^9 m^3 from Paleozoic carbonate sediments. Prior to the expansion of the SMA, nearly 11 10^9 m^3 of bitumen was expected to be recovered. The ultimate potential from within the area of expansion has yet to be estimated, leaving the total ultimate potential crude bitumen unchanged at 50 10^9 m^3.

3.2 Supply of and Demand for Crude Bitumen

This section discusses the production and disposition of crude bitumen. It includes crude bitumen production, upgrading of bitumen to various grades of synthetic crude oil (SCO), and disposition of both SCO and nonupgraded bitumen. The nonupgraded bitumen refers to the portion of crude bitumen production that is not upgraded but is blended with lighter-viscosity product (referred to as a diluent) in order to meet pipeline specifications for transportation through pipelines. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to SCO and is primarily used by refineries as feedstock.

"Upgrading" is the term given to a process that converts bitumen and heavy crude oil into SCO. Upgraders chemically alter the bitumen by adding hydrogen, subtracting carbon, or both. In upgrading, the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. Most oil sands coke is stockpiled as a byproduct of the upgrading process, and a small amount is burned in small quantities to generate electricity. Elemental sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, which is mainly used to manufacture fertilizers.

Pentanes plus and SCO are the two main types of diluent used to dilute bitumen for transport in pipelines, although naphtha and light crude oil can also be used to allow bitumen to meet pipeline specifications. Heated and insulated pipelines can decrease the amount of diluent needed to move bitumen through pipelines. Pentanes plus is lighter than SCO, which means a smaller volume of pentanes plus is required to move bitumen through a pipeline. On average, a blend of bitumen and pentanes plus will contain 30 per cent pentanes plus, whereas a blend using SCO will contain up to 50 per cent SCO.

If pentanes plus is used as diluent to transport bitumen to destinations within Alberta, it is usually recycled. However, if pentanes plus is used to transport bitumen to markets outside Alberta, it is generally not returned to the province. Instead, it is used as part of the feedstock for upgraders and refineries downstream. In July 2010, Southern Lights Pipeline delivered diluent from PADD II to Alberta.

The forecast of crude bitumen and SCO production relies heavily on information provided by project sponsors. This includes data on production capacity submitted during a project's application process, in addition to other publicly available materials such as quarterly reports, presentations, and press releases that provide information on delays in bringing the resource on stream. A project's viability depends largely on the cost-price relationship between production, operating, and transportation costs (supply) and the market price for bitumen and SCO (demand). Other factors include the refining capacity to handle bitumen or SCO and competition with other sources of supply in U.S. and Canadian markets. The forecasts for crude bitumen and SCO include production from existing projects, expansions of existing projects, and new projects that have been granted approval. Demand for SCO and nonupgraded bitumen in Alberta is based on refinery demand and SCO used for transportation needs. Alberta SCO and nonupgraded bitumen supply in excess of Alberta demand is marketed outside the province.

Project sponsors' projections of existing and future bitumen production can change over time for various reasons. Large oil sands production projects are complex and capital-intensive. They require long lead and construction times, making the projects vulnerable to material and labour cost increases throughout the planning, construction, and production phases.

3.2.1 Crude Bitumen Production—2010

Surface mining and in situ production for 2010 are shown graphically by OSA in **Figure S3.1**. In 2010, Alberta produced 256.3 thousand (10^3) m^3/d of crude bitumen from all three areas, compared with 236.7 10^3 m^3/d in 2009. Of this additional 19.6 10^3 m^3/d increase in production, 14.6 10^3 m^3/d is in situ and 5.0 10^3 m^3/d is mining. Regionally, in situ production appears strongest in Athabasca (23.4 per cent increase) followed by Cold Lake (8.3 per cent increase). In situ production in Peace River represented the only decline at 11.1 per cent.[3] Combined, production for all three in situ areas grew by 13.8 per cent, compared with 3.8 per cent growth for mined bitumen production.

Overall this incremental increase in production of 19.6 10^3 m^3/d represents an annual increase of 8.3 per cent. In situ production is accounting for an increasing share of the total production and stands to overtake production from mining. In 2010, total in situ production accounted for 47 per cent of total bitumen production, compared with 45 per cent in 2009. **Figure S3.2** shows combined nonupgraded bitumen and SCO production as a percentage of Alberta's total crude oil and equivalent production. Combined SCO and nonupgraded bitumen production volumes have increased from 40 per cent of the province's total crude oil production in 2000 to 72 per cent in 2010.

3.2.1.1 Mined Crude Bitumen

Annual mined production growth was 5.0 10^3 m^3/d in 2010 as daily volumes grew to 136.2 10^3 m^3/d, up from 131.2 10^3 m^3/d in 2009. Production growth was slower in 2010 at 3.8 percent, compared with growth of 14 per cent during 2009. Production gains at CNRL totalled 7.5 10^3 m^3/d, but this was nearly offset by Suncor and Shell production declines of 3.7 10^3 m^3/d and 1.2 10^3 m^3/d, respectively. Syncrude increased its production by 1.4 10^3 m^3/d at its Mildred Lake mine and 1.0 10^3 m^3/d at Aurora. At present, all mined bitumen in Alberta serves as feedstock for upgraders producing SCO.

Syncrude (Mildred and Aurora), Suncor, Shell (Muskeg River and Jackpine), and CNRL's Horizon account for 41, 31, 15, and 13 per cent of total mined bitumen, respectively.

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[3] This decline is due to incorrect volumes being reported in 2009. The reported volumes corrected in 2010 have resulted in a drop in annual production volumes.

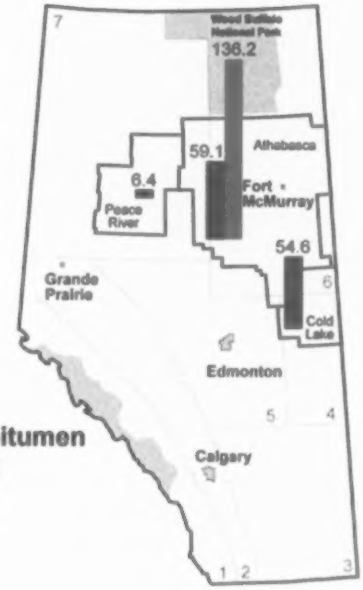

7
Wood Buffalo National Park
136.2
Athabasca
59.1
Fort McMurray
6.4
Peace River
54.6
6
Cold Lake
Grande Prairie
Edmonton
5
4
Calgary
1
2
3

Figure S3.1
Production of bitumen in Alberta, 2010 (10^3 m^3/day)

- ■ In situ
- ▨ Mined bitumen

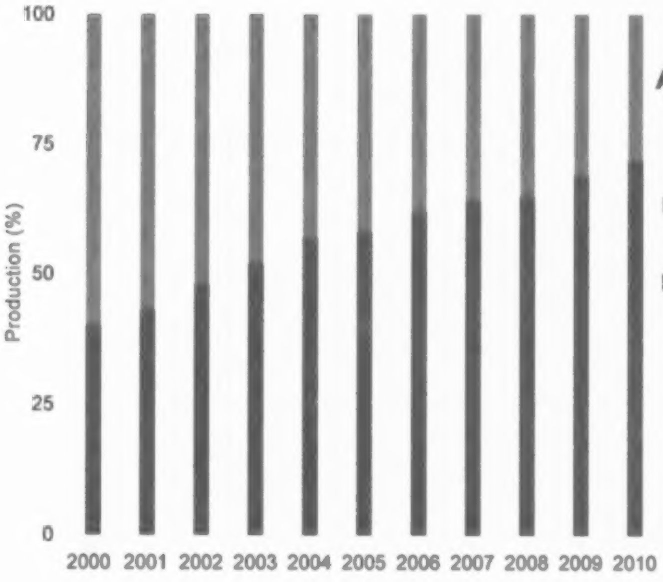


Figure S3.2
Alberta crude oil and equivalent production

- ▨ Conventional crude oil and pentanes plus
- ■ SCO and bitumen

Overall production at Syncrude was up almost 5 per cent in 2010 after recovering from an extended shutdown in 2009. Production in 2010 increased to 55.5 10^3 m^3/d, compared with 53.1 10^3 m^3/d in 2009. This higher production was due to reliability improvements made during the 2009 shutdown.

Mined bitumen production at Suncor declined 8.1 per cent in 2010 due to constraints caused by two fires at one of their two upgraders in December 2009 and February 2010. Production in 2010 declined to 42.3 10^3 m^3/d, down from 46.0 10^3 m^3/d in 2009.

Shell's Muskeg River and Jackpine Mine projects produced 21.0 103 m^3/d in 2010 compared with 22.2 10^3 m^3/d in 2009, a decrease of 5.4 per cent from 2009 levels. Output from the Jackpine Mine project start-up was offset by an extended turnaround in April 2010 at the Muskeg River mine.

CNRL's Horizon project almost doubled its production in 2010 compared with the previous year. CNRL's 2010 production was 17.3 10^3 m^3/d, compared with 9.8 10^3 m^3/d in 2009, a 76 per cent increase. The mine reached 91 per cent of its design capacity in the second quarter of 2010, averaging 83 per cent for the year. In early 2011, production was hampered by a coker fire that halted production. CNRL expects to operate at 50 per cent capacity in the second quarter of 2011 and at full capacity thereafter.

3.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production for 2010 increased to 120.1 10^3 m^3/d from 105.5 10^3 m^3/d in 2009. This 14.6 10^3 m^3/d increase represents a 13.8 per cent annual increase, on par with the 13.8 per cent increase in 2009. Since 2002, in situ crude production has grown at an average of 10.9 per cent per year.

Annual total in situ bitumen production, along with the number of bitumen wells on production for each year, is shown in **Figure S3.3**. The number of producing bitumen wells has increased along with in situ crude bitumen production from 2300 in 1992 to about 10 050 in 2010. The average annual productivity of in situ bitumen wells remained relatively flat between 1992 and 2004 at a level of 8.0 m^3/d, but began to climb in 2005 to average 8.7 m^3/d, reaching 10.9 m^3/d by 2009 and 11.9 m^3/d in 2010 as the percentage of SAGD wells increased.

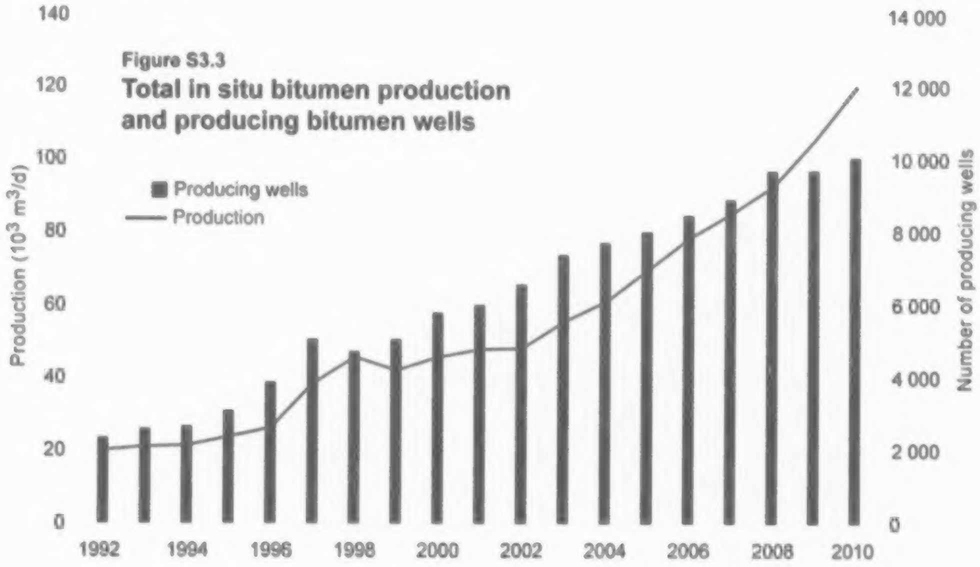


Figure S3.3

Total in situ bitumen production and producing bitumen wells

Figure S3.4 shows historical in situ production by OSA. While the Cold Lake OSA has traditionally been the major source of crude bitumen recovery, this changed in 2010 when Cold Lake's share of the total production dropped from 48 per cent to 45 per cent. Production from the Athabasca OSA now accounts for 49 per cent of total in situ production. In 2010, the Athabasca, Cold Lake, and Peace River OSAs each produced 59.1 10^3 m^3/d, 54.6 10^3 m^3/d, and 6.4 10^3 m^3/d, respectively. In 2010, annual production growth rates for the Athabasca and Cold Lake OSAs were 23 per cent and 8 per cent respectively, compared with their 10-year average growth rates of 25 per cent and 4 per cent. As a result of corrections made to reported volumes in 2010, as noted earlier, production from the Peace River OSA declined by 11 per cent in 2010 compared to its 10-year average growth rate of 24 per cent. With the correct volumes for the Peace River OSA now being reported, it is expected that future growth in production will continue along its historical 10-year trend. Significant increases in production within the Athabasca OSA since 2002 are due to SAGD development, while increases in the Peace River OSA are largely the result of primary production in the Seal area.

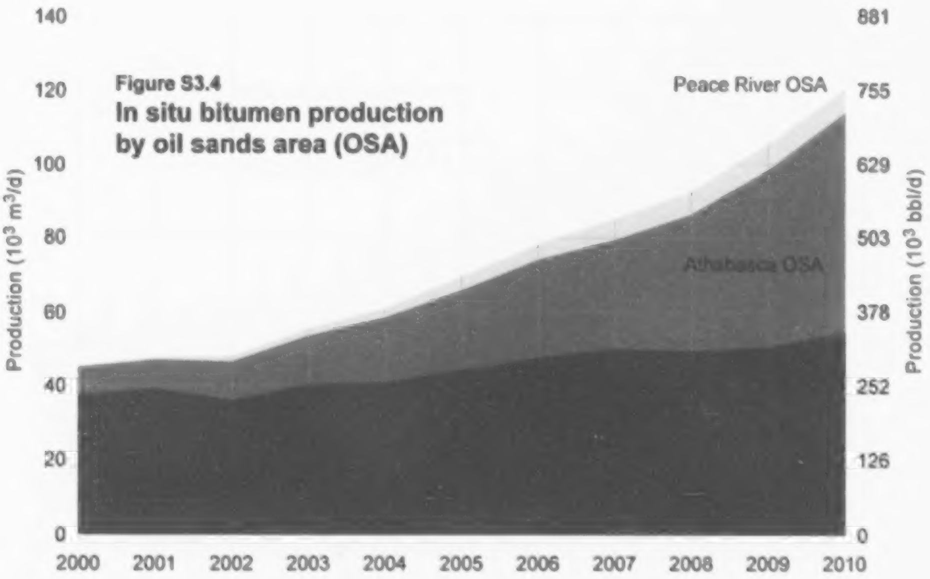


Figure S3.4
In situ bitumen production by oil sands area (OSA)

Currently, there are three main methods for producing in situ bitumen: primary production, cyclic steam stimulation (CSS), and SAGD. In situ bitumen production by recovery method per year is shown in **Figure S3.5**. Primary production includes those schemes that use water and polymer injection as a recovery method. In 2010, 32 per cent of in situ production was recovered by CSS, 42 per cent by SAGD, and 26 per cent by primary schemes. SAGD production was responsible for 82 per cent of the total increase in production between 2009 and 2010. CSS production reversed its negative trend in 2010, adding 4.8 10^3 m^3/d in production, a 14 per cent increase over 2009 production levels.

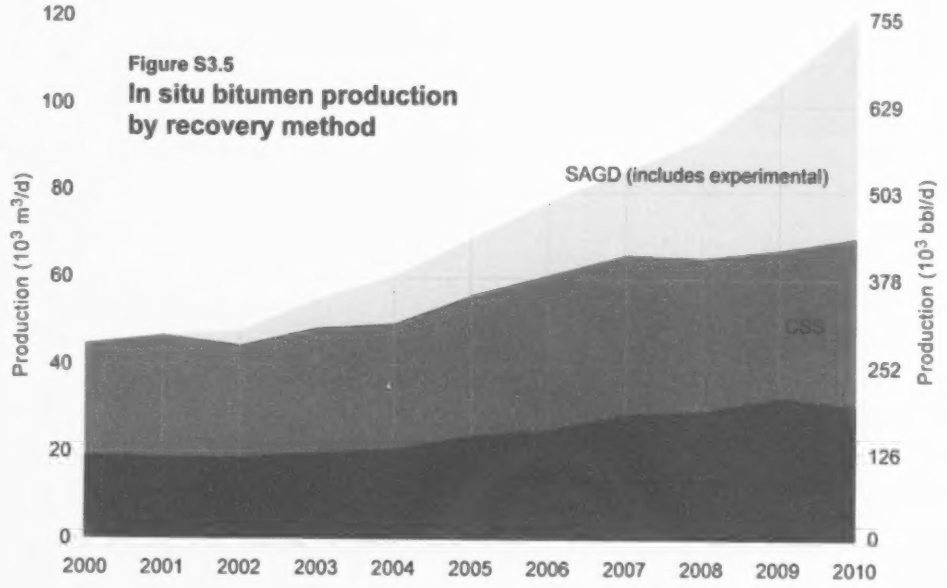


Figure S3.5

In situ bitumen production by recovery method

As discussed earlier, total productivity of in situ wells has been increasing, largely due to an increase in SAGD as a method of recovery. **Figure S3.6** shows the average well productivity in 2010 by recovery method for primary (including enhanced recovery), CSS, and SAGD. SAGD technology has been in use since 2001 and is the preferred method of recovery for most new projects in the Athabasca OSA.

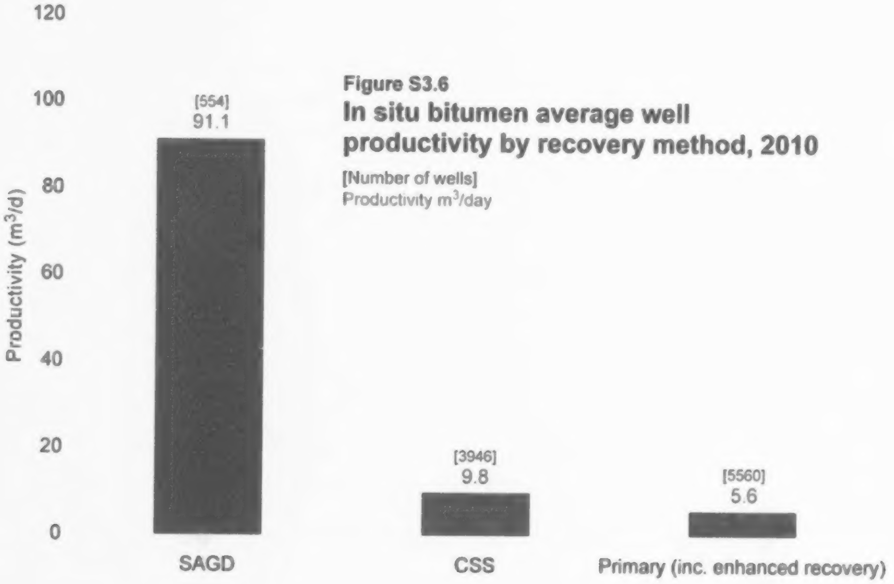


Figure S3.6

In situ bitumen average well productivity by recovery method, 2010

[Number of wells]
Productivity m^3/day

3.2.1.3 Synthetic Crude Oil

Currently, all Alberta mined bitumen and a portion of in situ production (11 per cent) are upgraded to SCO. SCO production in 2010 was 126.4 10^3 m^3/d, compared with 121.7 10^3 m^3/d in 2009. **Table 3.6** shows SCO production in 2010 by individual operator.

Table 3.6 Synthetic crude oil production in 2010[a]

Company/project name	Production (10^3 m^3/d)
Syncrude	47.4
Suncor	41.1
Shell Canada Scotford	19.7
CNRL Horizon	14.6
Nexen/OPTI Long Lake	3.5

[a] Any discrepancies are due to rounding.

Alberta's five upgraders produce a variety of synthetic products: Suncor produces light sweet and medium sour crudes, including diesel; Syncrude, CNRL Horizon, and Nexen Inc. (Nexen) Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell Scotford Refinery, as well as sweet and heavy SCO. Production from new upgraders is expected to align in response to specific refinery product requirements.

Most of the projects use coking as their primary upgrading technology and achieve volumetric liquid yields (SCO produced/bitumen processed) of 80 to 90 per cent, whereas projects employing hydroconversion can achieve volumetric liquid yields of 100 per cent or more. CNRL's Horizon project uses delayed coking, as their primary upgrading technology. The Nexen Long Lake project uses OrCrude™, a carbon rejection upgrading process using conventional thermal cracking, distillation, and solvent deasphalting equipment. A key aspect of this process is the removal of coke precursors (asphaltenes) prior to thermal cracking of the upgrader feed.

3.2.1.4 Petroleum Coke

Petroleum coke is a byproduct of the oil sands upgrading process that is currently being stockpiled in large amounts in Alberta and is considered a potential source of energy. It is high in sulphur but has a lower ash than conventional fuel coke. Petroleum coke has the potential of becoming a future energy resource through gasification and is discussed in more detail in Coal section.

Suncor Energy Inc. and Syncrude Canada Ltd. operate Alberta's two largest oil sands mines near Fort McMurray. Built with the capacity for both on-site extraction and upgrading, Syncrude and Suncor both produce coke. The CNRL Horizon project that commenced operations in 2009 has an oil sands mine, on-site extraction and upgrading capabilities that use delayed coking technology and also produces coke.

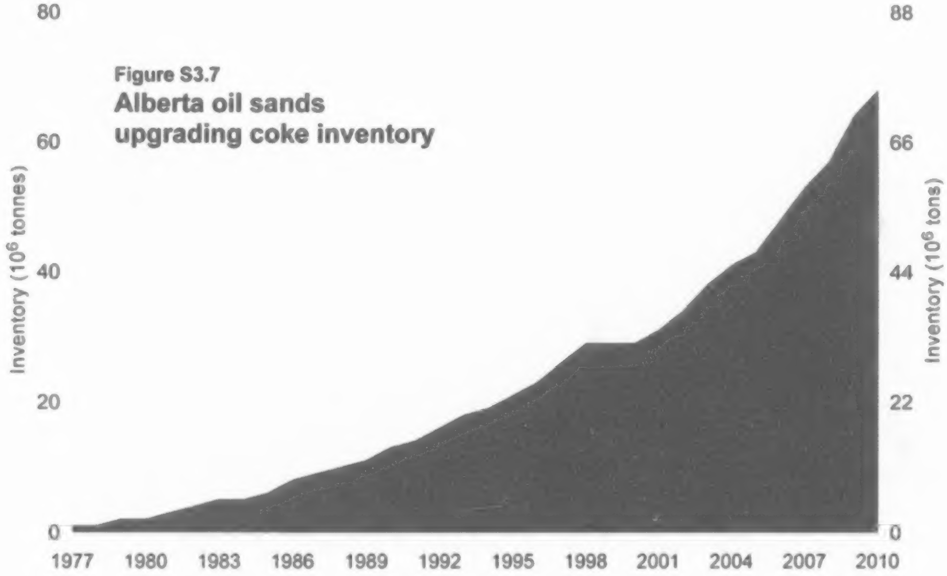
Suncor has been burning sulphur-rich coke in its boilers for decades at its mine near Fort McMurray and is responsible for most of the total coke used as a site fuel. In 2010, Suncor used approximately 30 per cent of its annual coke production as site fuel and sold approximately 20 per cent through its Energy

Marketing Group. Syncrude began using coke as a site fuel in 1995 and by 2010 used 21 per cent of its annual coke production as site fuel. At CNRL's Horizon project, all coke produced is stockpiled, accounting for approximately 3 per cent of the total inventories.

Suncor and Syncrude are seeking alternatives in how to use their coke surplus and are exploring ways of using it as a reclamation material. In August 2009, Suncor applied to the ERCB for permission to use coke inventories for capping two tailings ponds. Suncor estimated that it could use about 40 million tonnes of the coke stockpiled for nonenergy use for reclamation purposes. No decision has been made on the application to date.

Statistics of coke inventories reported in *ST43: Mineable Oil Sands Annual Statistics* show general increases in the total closing inventories per year, as illustrated in **Figure S3.7**. In 2010, coke inventories reached 68 million tonnes, up 4 million from 2009. This represents a change of approximately 6 per cent, whereas in 2009 there was a 12 per cent change over 2008. Coke inventories are expected to continue their growth with the recent addition of CNRL's Horizon project, unless significant alternative uses are found. Inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders.

Figure S3.7
Alberta oil sands upgrading coke inventory



3.2.2 Crude Bitumen Production—Forecast

3.2.2.1 Mined Crude Bitumen

In projecting the future supply of bitumen from mining, the ERCB considered potential production from existing facilities and supply from future projects. The projects considered for the forecast are shown in **Table 3.7**.

Table 3.7 Surface mined bitumen projects

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Suncor/Total E&P Canada			
Voyageur South Phase 1	TBD*	19.1	Application
Syncrude			
Stage 3 debottleneck	TBD	7.4	Announced
Stage 4 expansion	TBD	22.2	Announced
Alberta Oil Sands Project (Shell)			
Muskeg River expansion and debottlenecking	TBD	18.3	Approved
Jackpine Phase 1A	2010	15.9	Operating
Jackpine Phase 1B	TBD	15.9	Approved
Jackpine Phase 2	TBD	15.9	Application
Pierre River Phase 1	TBD	15.9	Application
Pierre River Phase 2	TBD	15.9	Application
CNRL			
Horizon Phase 2/3	TBD	21.5	Approved
Suncor/Total E&P Canada			
Fort Hills Phase 1	2016	26.2	Approved
Fort Hills debottleneck	TBD	4.0	Approved
Imperial Oil/Exxon Mobil			
Kearl Phase 1	2012	15.9	Under construction
Kearl Phase 2	TBD	15.9	Approved
Kearl Phase 3	TBD	15.9	Approved
Total E&P Canada/Suncor			
Joslyn (North)	2018	15.9	Approved

Source: ERCB, company releases, and Strategy West.

* To be determined.

Due to uncertainties regarding timing and project scope, some projects, such as Silver Birch's Equinox and Frontier projects, have not been considered in the ten-year forecast. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

In projecting total mined bitumen over the forecast period, the ERCB considered the effects from positive factors, such as the increasing crude oil price forecast and strengthening economic conditions. Effects from these factors will be tempered by the current tight light/bitumen differential, escalating construction costs, anticipated construction delays, and availability of both suitable and timely refinery capacity, all of which can delay the production schedule for these projects. By 2020, mined bitumen is expected to reach 244.9 10^3 m^3/d. This represents an upward revision of 4 per cent compared with the end of the forecast period in last year's report. Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure S3.8**, which shows that the percentage of mined bitumen to total production is expected to decrease from 53 per cent in 2010 to 45 per cent in 2020.

3.2.2.2 In Situ Bitumen

Similar to surface mining, the future supply of in situ bitumen includes production from existing projects, expansions to existing projects, and development of new projects. In projecting the production from existing and future schemes, the ERCB considered all approved projects, projects currently before the ERCB for approval, and applications it expects to receive for projects over the next 12 to 18 months and has assumed that existing projects will continue producing at their current or projected production levels over the forecast period. To this projection the ERCB has added crude bitumen production from new and expanded schemes. The production forecasts from future crude bitumen projects takes into account past experiences of similar schemes, project modifications, crude oil and natural gas prices, light crude and bitumen price differentials, pipeline availability, and the ability of North American markets to absorb the increased volumes.

The current forecast has increased over last year mainly due to higher crude oil prices, the recent influx of foreign capital investment, and increased geopolitical risk in other parts of the world. In addition, recently shelved projects are resuming and new projects are being announced and moving through the regulatory process. As illustrated in **Figure S3.8**, the ERCB expects in situ crude bitumen production to increase to 304.7 10^3 m^3/d by 2020. This represents an increase of 12.4 per cent when compared to the end of the forecast period in last year's report. Based on this projection, in situ bitumen production will exceed mined bitumen production by 2015 and will account for 55 per cent of total bitumen produced by 2020.

In projecting the future supply of in situ bitumen, the ERCB considered potential production from existing facilities and supply from future projects. The projects considered for the forecast are shown in **Table 3.8.**

Table 3.8 In situ crude bitumen projects

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Athabasca Region			
Alberta Oil Sands			
Clearwater West	TBD	1.6	Application
Athabasca Oil Sands			
Dover Phase 1-5	TBD	40.0	Application
Cenovus			
Christina Lake Phase C	2011	6.4	Under Construction
Christina Lake Phase D	2013	6.4	Under Construction
Christina Lake Phase E-G	TBD	19.2	Application
Foster Creek Phase F	TBD	4.8	Approved
Foster Creek Phase G-H	TBD	9.6	Approved

Table 3.8 In situ crude bitumen projects (continued)

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Narrows Lake Phase 1A-1B	TBD	20.6	Application
Telephone Lake (Borealis) Phase A	TBD	5.6	Application
CNRL			
Kirby Phase 1	TBD	7.2	Application
Connacher			
Great Divide Expansion	TBD	3.8	Application
ConocoPhillips	TBD		
Surmont Phase 2	2014	17.3	Under Construction
Devon			
Jackfish 2	2011	5.6	Under Construction
Jackfish 3	TBD	5.6	Application
Grizzly Oil Sands			
Algar Phase 1-2	TBD	1.8	Application
E-T Energy			
Poplar Creek Commercial	TBD	1.6	Application
Harvest			
BlackGold Phase 1	TBD	1.6	Approved
BlackGold Phase 2	TBD	3.2	Application
Husky			
Sunrise Phase 1	2014	9.5	Under Construction
Sunrise Phase 2-3	TBD	22.2	Approved
Ivanhoe			
Tamarack Phase 1-2	TBD	6.4	Application
JACOS			
Hangingstone Expansion	TBD	5.6	Application
Laricina			
Saleski Phase 1	TBD	2.0	Application
MacKay Operating Corp.			
MacKay River Phase 1-4	TBD	24.0	Application
MEG			
Christina Lake Phase 3A-3C	TBD	23.7	Application
Nexen			
Kinosis Phase 1-3	TBD	19.2	Approved
Petrobank			
May River Phase 1	TBD	1.6	Approved
Southern Pacific			
McKay Phase 1	TBD	1.9	Approved
Statoil			
Kai Kos Dehseh Leismer Commercial	TBD	1.6	Approved
Kai Kos Dehseh Leismer Expansion	TBD	3.2	Approved
Kai Kos Dehseh Corner	TBD	6.4	Approved
Suncor			
Firebag Phase 3	2011	9.9	Under construction
Firebag Phase 4-6	TBD	29.7	Approved
MacKay Phase 2	TBD	6.4	Approved
Sunshine Oilsands			
West Ells Phase 1-2	TBD	1.6	Approved
Value Creation			
Terre de Grace Phase 1	TBD	1.6	Application

Table 3.8 In situ crude bitumen projects (continued)

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Cold Lake Region			
Husky			
Caribou Lake Phase 1	TBD	1.6	Approved
Imperial			
Cold Lake Phases 14-16	TBD	4.8	Approved
Koch Exploration			
Gemini Phase 2 (inc. Pilot)	TBD	1.8	Application
Osum			
Taiga Phase 1-3	TBD	5.6	Application
Shell			
Orion (Hilda Lake) Phase 2	TBD	1.6	Approved
Peace River Region			
Shell Peace River			
Carmon Creek Phase 1-2	TBD	10.6	Application

Source: ERCB, company releases, and Strategy West.

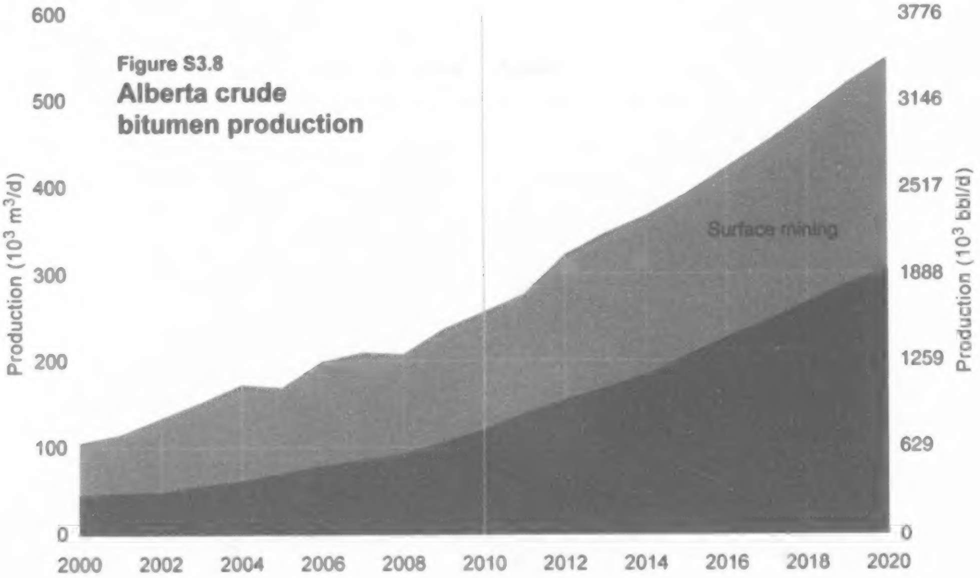


Figure S3.8
Alberta crude bitumen production

In 2010, approximately 11 per cent of in situ production in Alberta was upgraded to SCO. It is expected that by the end of the forecast period, about 13 per cent of in situ bitumen production will be used as feedstock for SCO production within the province, compared with the 18 per cent projection in the 2009 forecast.

3.2.2.3 Synthetic Crude Oil

To forecast SCO production, the ERCB included existing production from Suncor, Syncrude, Shell, CNRL, and Nexen projects plus their planned expansions and the new production expected from projects listed in **Table 3.9**. Production from future SCO projects considers the high cost of engineering and material and the substantial amount of skilled labour required for expansions and new projects. The ERCB also recognizes that other key factors, such as the forecast of oil prices, the narrow light/bitumen differential, the length of the construction period, and the market penetration of new synthetic volumes, will impact project timing.

Figure S3.9 shows the ERCB's projection of SCO production, which is expected to increase moderately from 126.4 10^3 m^3/d in 2010 to 131.9 10^3 m^3/d 2011. This moderate increase reflects the interruption in production caused by the fire at CNRL as well as the expected increase in production from the start-up of Shell's Scotford upgrader expansion. In 2012, production is expected to increase significantly to 165.1 10^3 m^3/d, assuming that all upgraders will return to normal operations. The forecast production increases to 223.3 10^3 m^3/d by 2020. This is an increase of 4 per cent from last year's end of the forecast period of 215 10^3 m^3/d.

Table 3.9 Synthetic crude oil projects

Company/project name	Start-up	SCO capacity (10^3 m^3/d)	Status
Athabasca Region			
Suncor/Total			
Voyageur Phase 1	2016	20.2	Approved
Voyageur Phase 2	TBD	10.0	Approved
Syncrude			
Stage 3 debottleneck	TBD	6.4	Announced
Stage 4 expansion	TBD	19.1	Announced
CNRL			
Horizon Phase 2/3	TBD	18.8	Approved
Nexen/OPTI			
Long Lake Phase 2	TBD	9.3	Approved
Value Creation Inc.			
Terre de Grace Pilot	TBD	1.3	Application
Industrial Heartland Region			
Alberta Oil Sands Project			
Scotford Upgrader 1 Expansion	2011	14.5	Commissioning
Shell			
Upgrader 2 Phase 1	TBD	15.9	Withdrawn
Upgrader 2 Phase 2	TBD	15.9	Withdrawn
Upgrader 2 Phase 3 - 4	TBD	15.9	Withdrawn
North West Upgrading			
NW Upgrader Phase 1	2014	7.4	Approved
NW Upgrader Phase 2	TBD	7.4	Approved
NW Upgrader Phase 3	TBD	7.4	Approved
Total E&P Canada			
Strathcona Upgrader Phase 1	TBD	21.9	Approved
Strathcona Upgrader Phase 2	TBD	13.8	Approved
Strathcona Upgrader debottlenecking	TBD	7.3	Approved

Source: ERCB, company releases, and Strategy West

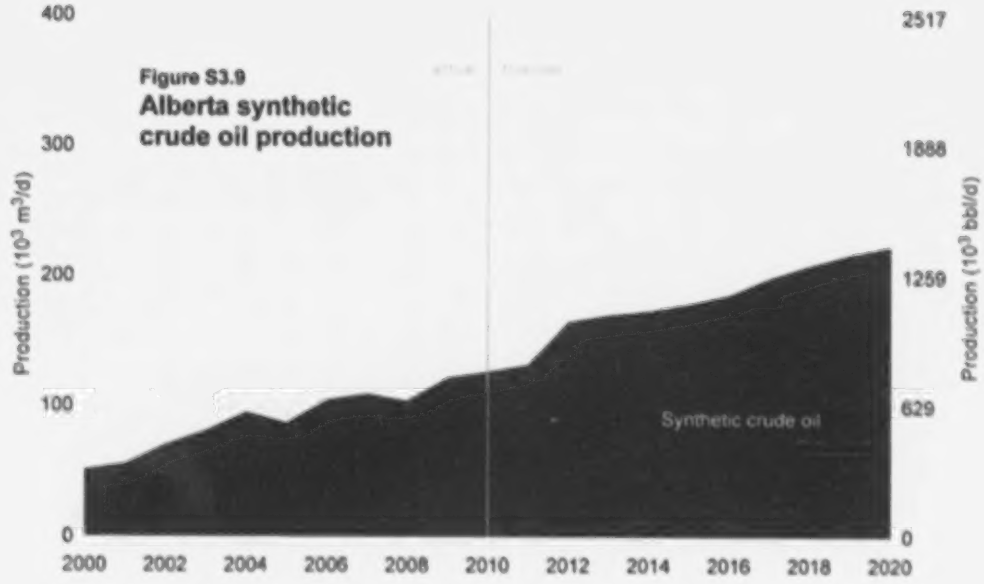


Figure S3.9
Alberta synthetic crude oil production

3.2.3 Supply Costs

The supply cost for a resource or project can be defined as the minimum constant dollar price required to not only recover all capital expenditures, operating costs, royalties and taxes but earn a specified return on investment. This price can then be compared with current market prices to assess whether a project or resource is economically attractive or it can be utilized for comparative project economics.

The supply cost calculation would typically produce a value received per unit of production. SAGD and stand-alone mining projects produce bitumen, whereas an integrated SCO mine produces a product much closer to West Texas Intermediate (WTI) crude oil. In order to provide more meaningful comparisons, the results of the supply cost analysis have been converted to a WTI price which is directly comparable to current market prices.

3.2.3.1 Assumptions

The substantial cost inflation suffered by projects in the last decade resulted in some operators delaying and deferring new projects. It also meant that capital cost information submitted in applications were no longer applicable in the new environment. Although each project is unique in its location and the quality of its reserves, this supply cost analysis relies on more generic project specifications and capital and operating cost estimates. Data selected for the analysis are provided in imperial units since North American price data are based on a US$WTI and are in **Table 3.10**.

The generic projects were determined by proposed activity. Although significant production currently comes from CSS projects, few new CSS projects have been proposed. The majority of proposed in situ projects use SAGD extraction methods.

Table 3.10 Supply cost project data

	Production				Purchased natural gas requirement	
Project type	**(10^3 m^3/d)**	**(bbl/d)**	**Capital cost range (millions of dollars)**	**Estimated supply cost $US WTI equivalent per barrel**	**(10^3 m^3 gas/ m^3 oil)**	**(mcf/bbl)**
In situ SAGD	4.8	30 000	900 to 1350	47 to 57	0.177	1
Stand-alone mine	15.9	100 000	5 000 to 7500	63 to 81	0.089	0.5
Integrated SCO	15.9	100 000	8 500 to 11500	88 to 102	0.124	0.7

A major component of operating cost is purchased natural gas for fuel and processing. This analysis assumes a value of $Cdn 6.64 per gigajoule real price at AECO-NIT throughout the project's life. The analysis uses a real discount rate of 10 per cent and has incorporated taxes on carbon dioxide emissions and costs for reclamation as operating costs.

3.2.3.2 Results

As the range for estimated supply costs demonstrate in **Table 3.10**, the current price environment, historical prices from 2007, and the ERCB WTI forecast strongly support the development of stand-alone in situ and mining projects. The supply cost range for the integrated SCO project is higher than the other two project types and is also higher than the average WTI prices between 2007 and 2010. However, the supply cost is below the current ERCB WTI forecast. The results of the supply cost analysis underpin the forecast continued growth in SAGD, mining, and integrated projects over the forecast period.

A major risk to the capital cost assumptions in this analysis would be the re-emergence of cost escalation that occurred in the last decade. When too many projects proceed, resources, such as labour, quickly become scarce, resulting in an escalation in capital and supply cost.

3.2.4 Pipelines

With the expected increase in both SCO and nonupgraded bitumen over the forecast period, it is expected that incremental pipeline capacity will be available to carry these products outside Alberta to current and expanded markets. Major pipeline projects completed in 2010 added approximately 165 10^3 m^3/d in incremental capacity exiting Western Canada. This incremental capacity allows the proposed increase in forecasted production to proceed to markets without curtailment through 2017. In addition, the proposed projects that are either currently under regulatory review or have been announced, if completed, are expected to provide enough transportation capacity throughout the forecast period.

Within Alberta, the current pipeline system's ability to expand, in addition to proposed projects, should provide adequate transportation capacity for the expected increases in SCO and nonupgraded bitumen production over the forecast period. The current pipeline systems in the Cold Lake and Athabasca areas are shown in **Table 3.11**. **Figure S3.10** shows the current pipelines and proposed crude pipeline projects within the Athabasca and Cold Lake areas. Numerals within parentheses in the following sections on existing and proposed pipelines in Alberta refer to the legend on the map in **Figure S3.10**.

Table 3.11 Alberta SCO and nonupgraded bitumen pipelines

Name	Destination	Current capacity (10^3 m^3/d)
Cold Lake Area pipelines		
Cold Lake Heavy Oil Pipeline	Hardisty	73.0
	Edmonton	
Husky Oil Pipeline	Hardisty	78.0
	Lloydminster	
Echo Pipeline	Hardisty	12.0
Fort McMurray Area pipelines		
Athabasca Pipeline	Hardisty	62.0
Corridor Pipeline	Edmonton	73.9
Syncrude Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	23.0
Access Pipeline	Edmonton	23.8
Waupisoo Pipeline	Edmonton	55.6
Horizon Pipeline	Edmonton	39.7

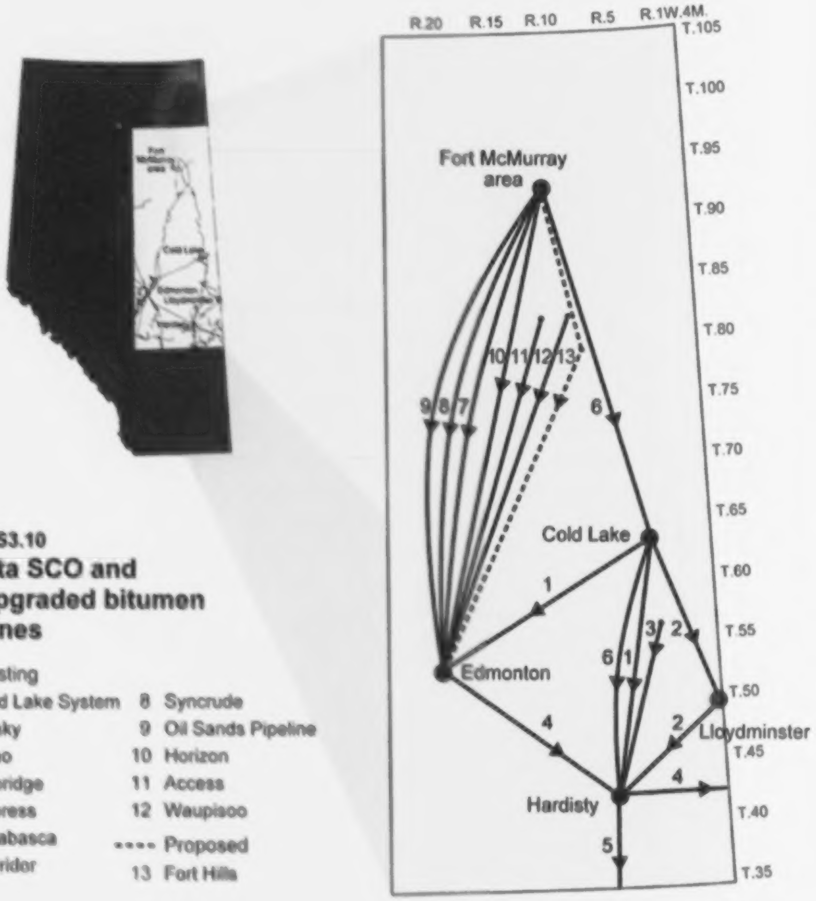


Figure S3.10
Alberta SCO and nonupgraded bitumen pipelines

R.20
R.15
R.10
R.5
R.1W.4M.
T.105
T.100
T.95
T.90
T.85
T.80
T.75
T.70
T.65
T.60
T.55
T.50
T.45
T.40
T.35
Fort McMurray area
9 8 7
10 11 12 13
6
Cold Lake
1
3 2
6 1
Edmonton
2
Lloydminster
4
4
Hardisty
5
— Existing
1 Cold Lake System
2 Husky
3 Echo
4 Enbridge
5 Express
6 Athabasca
7 Corridor
8 Syncrude
9 Oil Sands Pipeline
10 Horizon
11 Access
12 Waupisoo
---- Proposed
13 Fort Hills

3.2.4.1 Existing Alberta Pipelines

- The Cold Lake pipeline system (1) is capable of delivering heavy crude from the Cold Lake area to Hardisty and Edmonton.
- The Husky pipeline (2) moves Cold Lake crude to Husky's heavy oil operations in Lloydminster. Heavy and synthetic crude is then transported to Husky's terminal facilities at Hardisty, where oil is delivered into the Enbridge (4) or the Kinder Morgan Express pipeline (5) systems.
- The Echo pipeline system (3) is an insulated pipeline able to handle high-temperature crude, thereby eliminating the requirement for diluent blending. This pipeline delivers Cold Lake crude to Hardisty.
- The Enbridge Pipeline (4), described below, is an existing export pipeline.
- The Kinder Morgan Express Pipeline (5), described below, is an existing export pipeline.
- The Athabasca Pipeline (6) delivers semiprocessed product and bitumen blends to Hardisty. Its current capacity is 62 10^3 m^3/d but it has the potential to carry 90.6 10^3 m^3/d.
- The Inter Pipeline Fund Corridor pipeline (7) transports diluted bitumen from the Albian Sands mining project to the Shell Scotford Upgrader near Edmonton. The pipeline has recently been expanded from 30.2 10^3 m^3/d to 73.9 10^3 m^3/d through the construction of a 1.1 metre diluted bitumen line and conversion of the existing 0.61 metre line to transport diluent.
- The Syncrude Pipeline (formerly Alberta Oil Sands Pipeline) (8) is the exclusive transporter for Syncrude.
- The Oil Sands Pipeline (9) transports Suncor synthetic oil to the Edmonton area.
- The Access Pipeline (11) transports diluted bitumen from the Christina Lake area to facilities in the Edmonton area. Capacity of the pipeline is 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d.
- The Enbridge Waupisoo Pipeline (12) moves blended bitumen from the Cheecham Terminal, south of Fort McMurray, to the Edmonton area. The Waupisoo Pipeline has current capacity of 55.6 10^3 m^3/d, and is expandable to 95.3 10^3 m^3/d.
- Pembina Pipeline's Horizon Pipeline (10) is the exclusive transporter for CNRL's Horizon oil sands development. With an initial capacity of 39.7 10^3 m^3/d it transports SCO to the Edmonton area.
- The Rainbow Pipeline System (not shown on **Figure S3.10**), is owned by Plains Midstream, and transports Peace River oil sands crude and condensate from Rainbow Lake to Edmonton, with a capacity of 31.7 10^3 m^3/d.

3.2.4.2 Proposed Alberta Pipeline Projects

- From the Cheecham terminal, Enbridge is proposing to expand its existing Waupisoo (12) line to the Edmonton Terminal. The second expansion will increase the line's capacity for transporting oil sands crude from 38.1 10^3 m^3/d to 87.4 10^3 m^3/d by 2013.
- Enbridge also intends to expand its capacity to move oil sands crude from the Christina Lake region by expanding the capacity of its Athabasca system (6), which moves product into the Hardisty terminal.
- Enbridge's announced Fort Hills Pipeline system (13) has been deferred past its planned in-service date of 2011. Fort Hills Energy L.P. has until June 2011 to notify Enbridge on whether to proceed with the pipeline.

3.2.4.3 Existing Export Pipelines

Table 3.12 lists the existing export pipelines, with their corresponding destinations and capacities and **Figure S3.11** shows the existing export pipelines leaving Alberta.

- The Enbridge Pipeline, the world's longest crude oil and products pipeline system, delivers western Canadian crude oil to eastern Canada and the U.S. Midwest.
- The Kinder Morgan Express Pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends east into Wood River, Illinois.
- The Kinder Morgan Trans Mountain pipeline system transports crude oil and refined products from Edmonton to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State. Trans Mountain's current capacity is 47.7 10^3 m^3/d, assuming heavy oil represents some 20 per cent (historical average) of the total throughput. Without heavy oil receipts, pipeline capacity increases to 63.6 10^3 m^3/d.
- Rangeland Pipeline is a gathering system that serves as another export route for Cold Lake Blend to Montana refineries.
- The Milk River Pipeline delivers Bow River heavy crude to Montana refineries.
- TransCanada's Keystone pipeline commenced commercial operations in June 2010, shipping crude oil to markets in the U.S. Midwest.
- Enbridge's Alberta Clipper pipeline was also completed in 2010, shipping crude oil from Hardisty, Alberta to Superior, Wisconsin.

Table 3.12 Export pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Inc.		
Enbridge Pipeline	Eastern Canada U.S. east coast U.S. midwest	301.9
Alberta Clipper Pipeline	U.S. midwest	71.5
Kinder Morgan Express Pipeline	U.S. Rocky Mountains U.S. midwest	44.9
Trans Mountain Pipeline	British Columbia U.S. west coast Offshore	47.7
Plains Midstream Canada		
Milk River Pipeline	U.S. Rocky Mountains	18.8
Pacific Energy Partners, L.P.		
Rangeland Pipeline	U.S. Rocky Mountains	13.5
TransCanada Pipelines		
Keystone Pipeline	U.S. midwest	93.8

3.2.4.4 Proposed Export Pipeline Projects

Table 3.13 provides a summary of the numerous pipeline expansions and new pipeline projects that are proposed to deliver SCO and nonupgraded bitumen to existing and new markets. **Figure S3.11** shows the proposed export pipeline expansions and new pipeline export projects.

Table 3.13 Proposed export pipeline projects

Name	Destination	Incremental capacity (10^3 m^3/d)	Start-up date
Enbridge			
Gateway Pipeline	U.S. west coast Offshore	83.3	2015-2016
Kinder Morgan			
Trans Mountain (TMX)	British Columbia U.S. west coast Offshore		
TMX2		12.7	2012
TMX3		47.7	2013
TransCanada Pipeline			
Keystone XL Pipeline	U.S. Gulf Coast	111.3	2012

3.2.4.5 Rail Transportation

Rail may emerge as an alternate mode of transportation for bitumen and SCO to markets in the U.S., or to Asian markets via the west coast. The primary mode for transporting bitumen and SCO has traditionally been through pipeline systems, which transport product to different PADD regions in U.S. markets or to Asian markets via the west coast. Greater access to markets via alternate routes assists producers in obtaining the best possible price for their product. To take advantage of alternate routes and destinations, producers are exploring different modes of transportation, specifically rail.

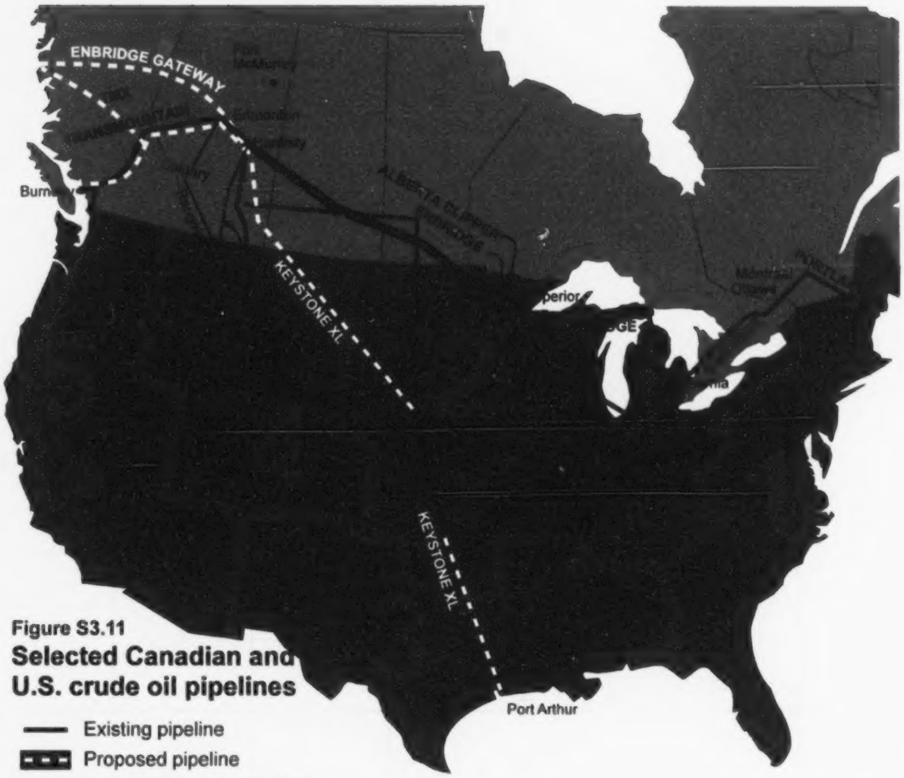

ENBRIDGE GATEWAY
Fort McMurray
TRANS MOUNTAIN
Edmonton
Hardisty
Burnaby
ALBERTA CLIPPER
KEYSTONE XL
Superior
Montreal
Ottawa
KEYSTONE XL
Port Arthur

Figure S3.11
Selected Canadian and U.S. crude oil pipelines

— Existing pipeline
▬ Proposed pipeline
•••• Extensions to new market
5 Petroleum administration district (PADD)

In 2005, Altex Energy proposed a pipeline project from Fort McMurray to the U.S. Gulf Coast, but recently re-evaluated the proposal to consider rail as an alternate solution. The proposed solution is a "pipeline-on-rail" system in which specialized rail cars would transport the raw, undiluted bitumen. The system is not illustrated on **Figure S3.11**, as rail infrastructure is significantly more complex in terms of the potential number of destinations and routes.

Rail already plays an important role in supplying the diluent needed to transport bitumen through pipelines. Currently, Canada's two main rail providers handle diluent at the Alberta Diluent Terminal in Edmonton in addition to shipping crude oil from the Bakken play in Saskatchewan.

In the short term, it is anticipated that rail will serve as a complimentary niche used by industry, depending on economic factors unique to each producer and refiner. Rail could allow producers to bypass short-term pipeline bottlenecks to take advantage of higher prices in PADD areas with refineries capable of handling heavier crudes.

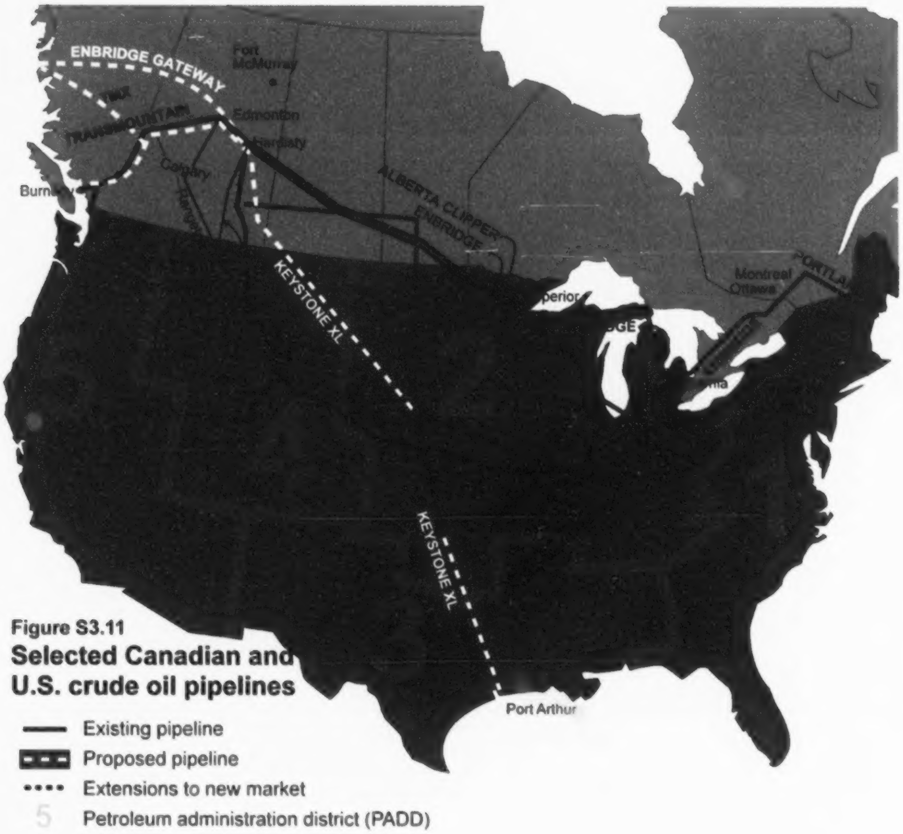

ENBRIDGE GATEWAY
Fort McMurray
TMX
TRANSMOUNTAIN
Edmonton
Hardisty
Burnaby
Calgary
ALBERTA CLIPPER
ENBRIDGE
KEYSTONE XL
KEYSTONE XL
Port Arthur
Montreal
Ottawa
PORTLA
perior
— Existing pipeline
▬ Proposed pipeline
•••• Extensions to new market
5 Petroleum administration district (PADD)

Figure S3.11
Selected Canadian and U.S. crude oil pipelines

In 2005, Altex Energy proposed a pipeline project from Fort McMurray to the U.S. Gulf Coast, but recently re-evaluated the proposal to consider rail as an alternate solution. The proposed solution is a "pipeline-on-rail" system in which specialized rail cars would transport the raw, undiluted bitumen. The system is not illustrated on **Figure S3.11**, as rail infrastructure is significantly more complex in terms of the potential number of destinations and routes.

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Longer term, however, growth in shipments of bitumen by rail will depend on several factors, such as the availability and supply of diluent, the prices offered by other commodity producers already using rail, and the development of crude oil handling facilities to fill cars with bitumen.

3.2.5 Demand for Synthetic Crude Oil and Nonupgraded Bitumen

Alberta oil refineries use SCO, bitumen, and other feedstocks to produce a wide variety of refined petroleum products. Overall, total Alberta demand for bitumen and SCO was 50.8 10^3 m^3/d in 2010, which is 14 per cent above the 2009 level of 44.4 10^3 m^3/d. This increase was primarily due to higher capacity utilization rates of refineries.

In 2010, the five refineries in Alberta, with a total capacity of 75.5 10^3 m^3/d, used 42.9 10^3 m^3/d of SCO and 2.5 10^3 m^3/d of nonupgraded bitumen. Additional demand for using SCO as diesel fuel and plant fuel accounted for 5.4 10^3 m^3/d in 2010, compared with 6.6 10^3 m^3/d in 2009, an 18 per cent decline. The Alberta refinery demand consumed 34 per cent of Alberta SCO production and 2 per cent of nonupgraded bitumen production in 2010, compared to the 29 per cent of Alberta SCO production and 3 per cent of nonupgraded bitumen production consumed in 2009.

Light sweet SCO has two principal advantages over light crude as a refinery feedstock: it is very low in sulphur and produces very little heavy fuel oil. The latter is particularly desirable in Alberta, where there is virtually no local market for heavy fuel oil. Among the disadvantages of using SCO in conventional refineries are the low quality output of distillate and the high level of aromatics (benzene) that must be recovered.

Overall demand for Alberta SCO and blended bitumen is influenced by many factors, including the price differential between light and heavy crude oil, expansion of refineries currently processing SCO and blended bitumen, altering the configuration of current light crude oil refineries to process SCO and blended bitumen, and the availability and price of diluent for shipping blended bitumen.

Refined SCO is also used by the oil sands upgraders as fuel for their transportation needs and as plant fuel. Suncor reports that it sells bulk diesel fuel to companies that transport it to other markets in tanker trucks. Suncor also operates a Suncor Energy-branded "cardlock" station where it sells diesel fuel supplied from its oil sands operation. The station is located on Highway 63 north of Fort McMurray. In 2009, the sale of refined SCO as diesel fuel oil accounted for about 7 per cent of Alberta SCO demand, compared to 11 per cent in 2009.

Figure S3.12 shows that in 2020, Alberta demand for SCO and nonupgraded bitumen will increase to about 62.9 10^3 m^3/d. It is projected that, on average, SCO will account for approximately 90 per cent of total Alberta demand and nonupgraded bitumen will account for approximately 10 per cent throughout the forecast period.

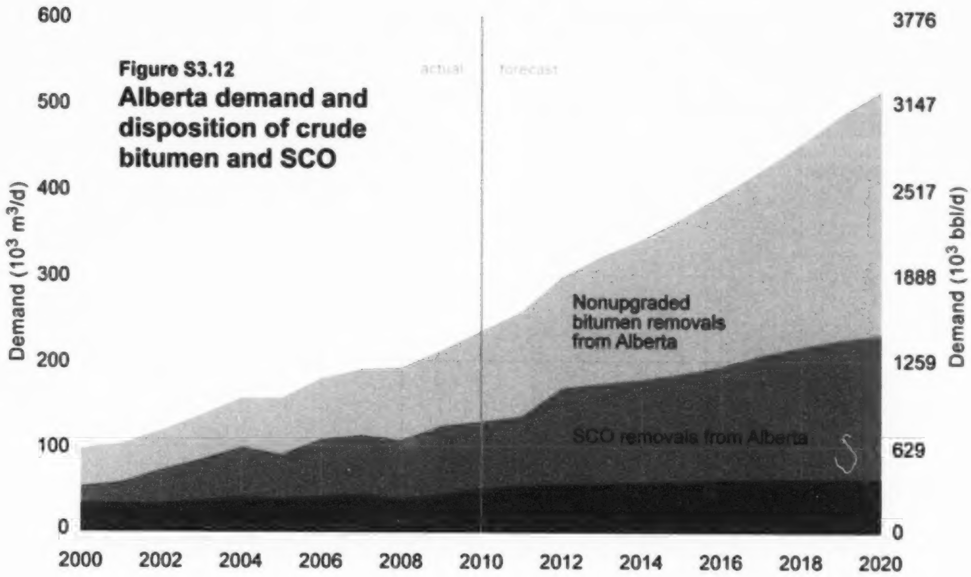


Figure S3.12
Alberta demand and disposition of crude bitumen and SCO

As illustrated in **Figure S3.12**, removals of SCO from Alberta will increase from 78.1 10^3 m^3/d in 2010 to 168.2 10^3 m^3/d in 2020, with removals of nonupgraded bitumen increasing from 105.6 10^3 m^3/d to 284.0 10^3 m^3/d over the same period.

Given the current quality of SCO, western Canada's nine refineries, with a total capacity of 99.8 10^3 m^3/d, are able to blend up to 34 per cent SCO and a further 2 per cent of blended bitumen with crude oil. These refineries receive SCO from both Alberta and Saskatchewan. In eastern Canada, the four refineries in the Sarnia area, with a combined total capacity of 56.6 10^3 m^3/d, are currently the sole ex-Alberta Canadian market for Alberta SCO.

Demand for Alberta SCO will come primarily from existing markets vacated by declining light crude supplies, as well as the overall anticipated increase in demand for refined products. The largest export markets for Alberta SCO and nonupgraded bitumen are the U.S. midwest, with a refining capacity of 592 10^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 99 10^3 m^3/d. The refineries in these areas are capable of absorbing a substantial increase in supplies of SCO and nonupgraded bitumen from Alberta. Other market regions that currently receive either SCO or nonupgraded bitumen, or both, are the eastern U.S., with a refining capacity of 222 10^3 m^3/d, the U.S. Gulf Coast, with a refining capacity of 1370 10^3 m^3/d, and the U.S. west coast, with a refining capacity of 512 10^3 m^3/d.

Traditional markets for Alberta SCO and nonupgraded bitumen are also expanding. These include western Canada, Ontario, the U.S. midwest, the northern Rocky Mountain region, and the U.S. west coast. Enbridge's Spearhead pipeline commenced operation in 2006 and delivers western Canadian crude oil to Cushing, Oklahoma. The oil being delivered to Cushing travels 2519 km through Enbridge's mainline system from Edmonton to Chicago before entering the Spearhead pipeline for the final 1046 km to Cushing. The ExxonMobil pipeline is currently the only pipeline providing oil sands crude delivery to the U.S. Gulf Coast. The Spearhead pipeline and the ExxonMobil pipeline are shown in **Figure S3.11**.

CRUDE OIL

4 // CRUDE OIL

HIGHLIGHTS

Remaining established reserves increased 3.7 per cent, the first increase since 2005.

Reserves additions from drilling replaced 124 per cent of production in 2010, compared with an average of 65 per cent per year over the past five years.

Production declined by 0.4 per cent, compared with an 8.6 per cent decline in 2009.

There were 2308 successful oil wells drilled in 2010, more than double the number drilled in 2009.

In Alberta, crude oil (also known as conventional oil) is deemed to be oil produced outside the oil sands areas, or if within the oil sands areas, it is from formations other than the Mannville or Woodbend. Crude oil is classified as light-medium if its density is less than 900 kilograms per cubic metre (kg/m^3) or as heavy if its density is 900 kg/m^3 or greater.

4.1 Reserves of Crude Oil

4.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of conventional crude oil in Alberta to be 236.9 million cubic metres (10^6 m^3), representing about one third of Canada's remaining conventional reserves. This is a year-over-year increase of 8.5 10^6 m^3, or 3.7 per cent, resulting from production, reserves adjustments, and additions from drilling that occurred during 2010.

Table 4.1 shows the changes in Alberta's reserves and production of light-medium and heavy crude oil as of December 31, 2010, while **Figure R4.1** shows the province's remaining conventional oil reserves over time. Remaining reserves have decreased to 19 per cent of the peak reserves of 1223 10^6 m^3 in 1969.

Table 4.1 Reserves and production change highlights (10^6 m^3)

	2010	2009	Change
Initial established reserves[a]			
Light-medium	2 450.3	2 429.3	+21.0
Heavy	379.4	365.6	+13.8
Total	**2 829.7**	**2 794.9**	**+34.8**
Cumulative production[a]			
Light-medium	2 278.1	2 262.2	+15.9
Heavy	314.7	304.3	+10.4
Total	**2 592.8**	**2 566.5**	**+26.3[b]**
Remaining established reserves[b]			
Light-medium	172.2	167.1	+5.1
Heavy	64.7	61.3	+3.4
Total	**236.9**	**228.4**	**+8.5**
	(1 491 10^6 bbl)		
Annual Production			
Light-medium	18.5	18.5	0.0
Heavy	8.1	8.3	-0.2
Total	**26.6**	**26.8**	**-0.2**

[a] Any discrepancies are due to rounding.

[b] May differ from annual production due to amendments to reported production, etc.

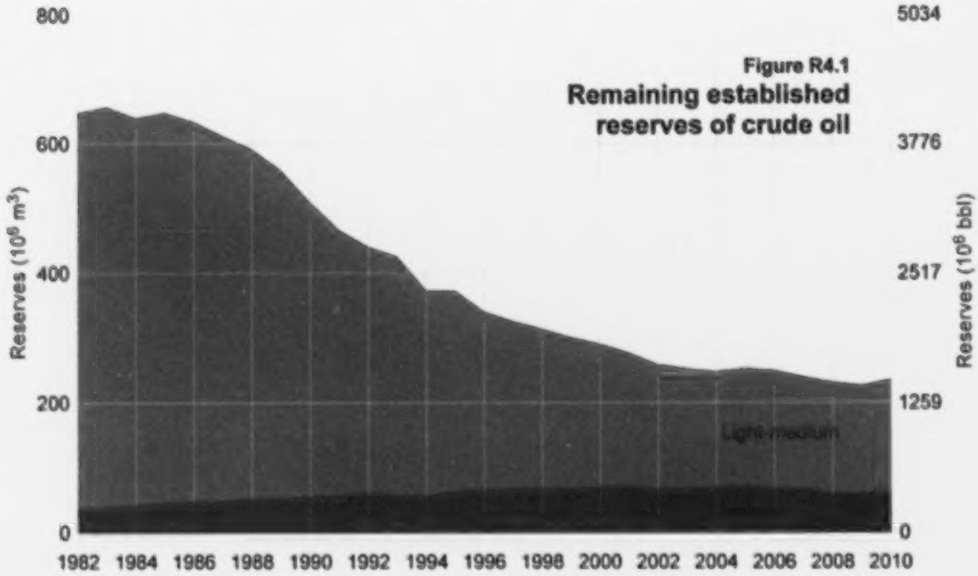


Figure R4.1
Remaining established reserves of crude oil

4.1.2 In-Place Resources

The total initial in-place and remaining in-place resources for conventional oil in Alberta stand at 11 245 10^6 m^3 and 8652 10^6 m^3, respectively. Sixty-five per cent (5403 10^6 m^3) of remaining in-place resources are in the largest 2 per cent of pools (260 pools), in which only about 27 per cent of oil in place is expected to be recovered. This represents a substantial resource for enhanced oil recovery (EOR) or for new drilling and completion techniques, such as high-density drilling and multistage fracturing technology. The Cardium and Mannville formations together make up the largest (35 per cent) share of this potential resource.

4.1.3 Established Reserves

The initial established reserves attributed to the 280 new oil pools defined in 2010 totalled 3.8 10^6 m^3 (an average of 12 thousand [10^3] m^3 per pool), compared to 4.0 10^6 m^3 in 2009. The increase in reserves per pool from last year's average of 10 10^3 m^3 can be attributed to an increase in horizontal wells, which are able to drain larger areas and recover more oil from a reservoir.

Table 4.2 shows the break down of this year's changes to initial established reserves into the following categories: new discoveries, development of existing pools, new and expansions to EOR schemes, and revisions to existing reserves. **Figure R4.2** shows the history of additions and net revisions to reserves. Net revisions represent the sum of all negative and positive revisions to pool reserves made over the year.

Table 4.2 Breakdown of changes in crude oil initial established reserves (10^6 m^3)

	Light-medium	Heavy	Total[a]
New discoveries	3.1	0.7	**3.8**
Development of existing pools	18.6	4.9	**23.5**
Enhanced recovery (new/expansion)	2.8	3.3	**5.8**
Revisions	-3.5	+5.2	**+1.7**
Total[a]	**+20.9**	**+13.9**	**+34.8**

[a] Any discrepancies are due to rounding.

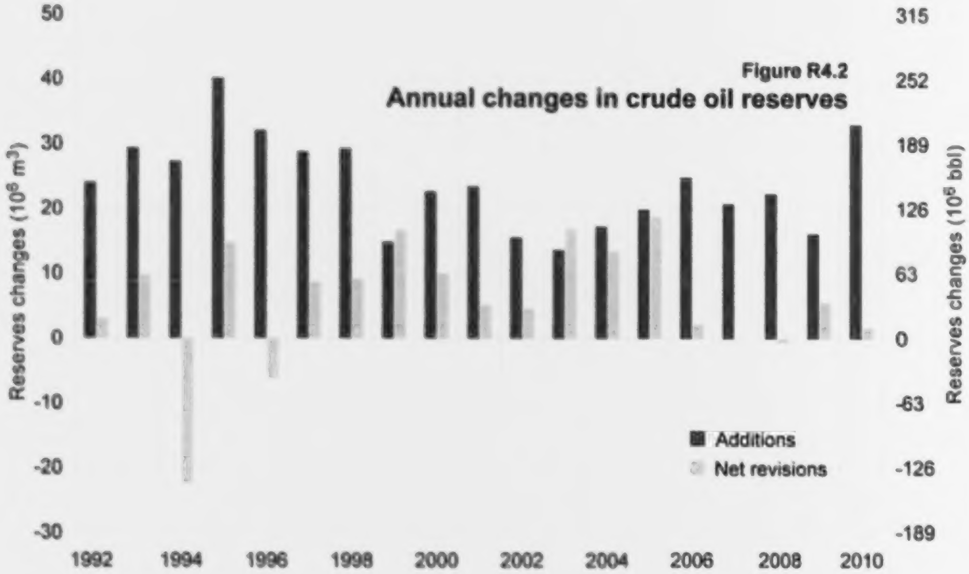


Figure R4.2
Annual changes in crude oil reserves

The ERCB processed 126 applications for new EOR schemes or expansions to existing schemes, resulting in reserves additions totalling 5.8 10^6 m^3, compared to 4.8 10^6 m^3 in 2009 (**Figure R4.3**). Step-out drilling of existing pools resulted in an increase in initial established reserves of 23.5 10^6 m^3, compared to 7.4 10^6 m^3 in 2009. Therefore, total reserves growth from new drilling plus new EOR schemes and expansions to EOR schemes (excluding revisions) amounted to 33.1 10^6 m^3, replacing 124 per cent of the 26.8 10^6 m^3 total conventional crude oil production in Alberta. This compares with a previous five-year average replacement ratio of about 70 per cent. Revisions to existing reserves resulted in an overall net change of +1.7 10^6 m^3. The total increase in initial established reserves for 2010 amounted to 34.8 10^6 m^3, significantly more than last year's 21.8 10^6 m^3. Section 4.1.3.1 contains further details on the reasons behind such a large increase in reserves growth. **Table B.3** in **Appendix B** provides a history of conventional oil reserves growth and cumulative production from 1968 to 2010.

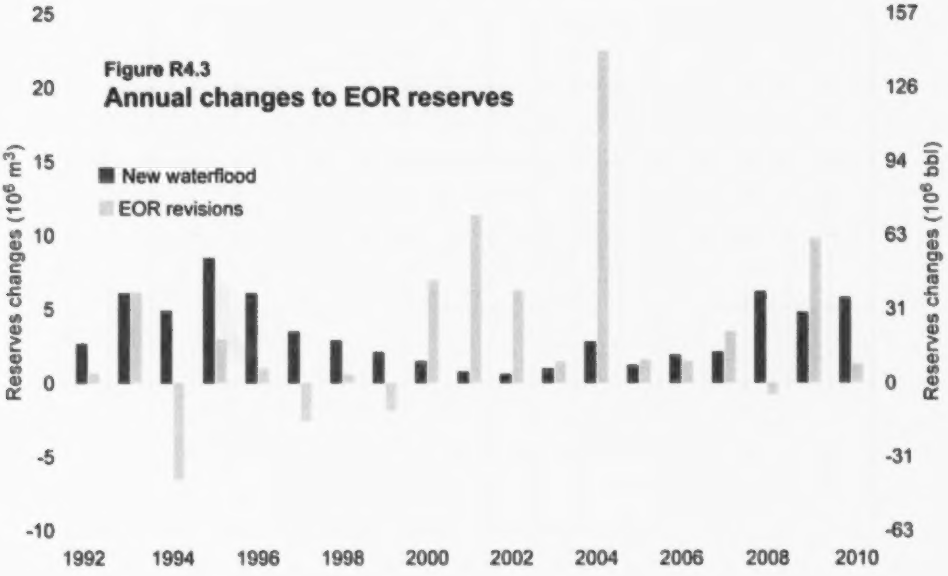


Figure R4.3

Annual changes to EOR reserves

As of December 31, 2010, oil reserves were assigned to 10 326 light-medium and 2730 heavy crude oil pools in the province. While many of these pools contain thousands of wells, most consist of a single well. About 65 per cent of the province's remaining oil reserves are in the largest 3 per cent of pools, with the largest of these in terms of remaining reserves being Pembina Cardium, Swan Hills Commingled Pool 001, Ferrier Commingled Pool 001, and Chauvin South Commingled Pool 001. In contrast, the smallest 75 per cent of pools contain only 6 per cent of remaining reserves. Ninety-five per cent of remaining reserves are in pools discovered before 1980.

While the median pool size has not changed over time, with initial established reserves at less than 10 10^3 m^3, the average size has declined from 150 10^3 m^3 in 1970 to about 20 10^3 m^3 recently. The Valhalla Commingled Pool 002 (previously the Doe Creek I and Dunvegan B pools), discovered in 1977, is the last major oil discovery (over 10 10^6 m^3) in Alberta. Initial established reserves for the pool are estimated at 12 630 10^3 m^3. The largest oil pools discovered since the beginning of 2000 include the Pembina Nisku II, Dixonville Montney C, and Killam North Upper Mannville F2F pools, with initial established reserves currently estimated at 1809 10^3 m^3, 1645 10^3 m^3, and 1412 10^3 m^3, respectively.

A detailed pool-by-pool list of reservoir parameters and reserves data is available on CD from ERCB's Information Services (see **Appendix C**).

4.1.3.1 Largest Reserves Changes

Revisions to existing pools over the past year resulted in a net total reserves change of +1.7 10^6 m^3. **Table 4.3** lists pools with the largest reserves changes in 2010, the most significant being the Pembina Cardium Pool. Initial established reserves increased almost 7 per cent, or 14 540 10^3 m^3, to 235 200 10^3 m^3 as a result of extensive horizontal drilling over the last several years, mostly to the south of the main pool. Horizontal multistage fractured wells have expanded the limits of the pool by allowing economic production from lower permeability sands and silts. Reserves were also increased in several Suffield Upper Mannville pools as new waterflood schemes came on stream and primary and waterflood reserves were revised higher because of positive results from infill horizontal drilling. There is potential for significant reserves growth from new horizontal wells in the Cardium Formation at Pembina, Willesden Green, and other fields. Horizontal multistage fractured wells are being drilled on the periphery of the main pools where permeability declines to less than 1 milliDarcies (mD) as a result of a change to a shalier facies. These techniques are also being used in many other formations, including Montney, Glauconitic, Pekisko, Duvernay, and Viking.

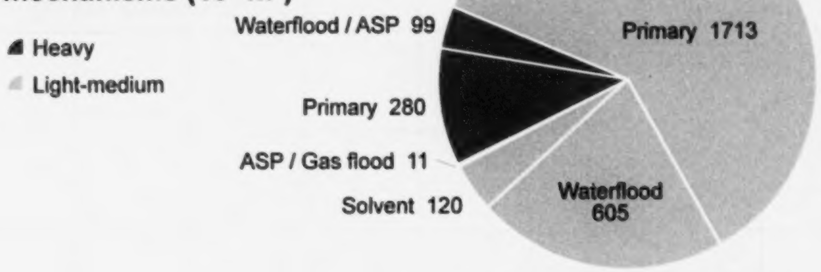
Table 4.3 Major oil reserves changes, 2010

	Initial established reserves (10^3 m^3)		
Pool	**2010**	**Change**	**Main reason for change**
Cecil Charlie Lake O	878	+199	Pool development
Chauvin South Commingled Pool 001	18 936	+2 726	New waterflood and reassessment of primary and waterflood reserves
Edgerton Woodbend A	615	+220	Reassessment of reserves
Grand Forks Upper Mannville K	7 461	-231	Reassessment of reserves
Halkirk East Viking A	358	+254	Pool development
Huxley Nisku A	64	-128	Reassessment of reserves
Kleskun Beaverhill Lake A	1 195	+219	Pool development
Lator Dunvegan A	234	-100	Reassessment of reserves
Lloydminster McLaren R	248	-102	Reassessment of reserves
Lloydminster Sparky G	2 516	+303	Pool development
Medicine Hat Glauconitic C	4 651	+445	Reassessment of waterflood reserves
Mooney Bluesky A	1 086	+334	New waterflood and polymer reserves
Pembina Cardium	235 200	+14 540	Pool development by horizontal drilling
Provost Cummings A	1 611	+253	Reassessment of waterflood reserves
Provost Upper Mannville A	1 694	+591	Reassessment of waterflood reserves
Rainbow Muskeg O	808	+253	New waterflood
Redwater Lower Viking II	1 002	+808	Pool development
Suffield Upper Mannville D	2 204	+199	New waterflood reserves
Suffield Upper Mannville J	8 649	+842	Reassessment of primary reserves
Suffield Upper Mannville CCC	1 876	+240	New waterflood reserves
Suffield Upper Mannville OOO	338	-154	Reassessment of reserves
Taber Taber I	886	+330	New waterflood
Taber North Glauconitic E	979	+200	New waterflood
Virginia Hills Belloy A	7 658	+247	Reassessment waterflood reserves
Worsley Gething-Montney A	392	+264	New waterflood

4.1.3.2 Distribution by Recovery Mechanism

Alberta's total initial volume in place and initial established reserves of conventional crude oil currently stand at 11 245 10^6 m^3 and 2830 10^6 m^3, respectively, yielding an overall recovery efficiency of 25 per cent. **Figure R4.4** and **Table 4.4** show the distribution of volume and reserves by recovery mechanism and crude oil density.

Figure R4.4
Initial established crude oil reserves based on recovery mechanisms (10^6 m^3)



Total = 2830 10^6 m^3 (17.8 10^9 bbl)

Waterflood recovery mechanisms have increased recovery from light-medium pools from an average of 15 per cent under primary depletion to 28 per cent under waterflood. Pools under solvent flood, on average, recover 12 per cent more than projected waterflood recovery. Primary recovery from heavy crude pools have increased from 8 per cent in 1990 to 12 per cent currently as a result of improved water handling, increased use of horizontal wells, improved fracturing techniques (including multistage fracturing), and increased drilling density. Incremental recovery from all waterflood projects represents about 25 per cent of the province's initial established reserves. Pools under solvent flood add another 4 per cent to the province's reserves. Alkali Surfactant Polymer (ASP) floods are becoming more popular, typically adding about 12 per cent recovery primary depletion.

4.1.3.3 Distribution by Geological Formation and Area

The distribution of reserves by geological period and Petroleum Services Association of Canada (PSAC) geographical area is depicted in **Figure R4.5** and **Figure R4.6**, respectively.

The percentage of remaining reserves in the Lower Cretaceous has increased to about 40 per cent in 2010 compared to 16 per cent in 1990. The Lower Cretaceous is increasingly becoming the major source of conventional oil.

Table 4.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2010

Crude oil type and pool type	Initial volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)				Average recovery (%)			
		Primary	Waterflood/ gas flood	Solvent flood	Total	Primary	Waterflood/ gas flood	Solvent flood	Total
Light-medium									
Primary depletion	4 332	888	0	0	**888**	20	-	-	**20**
Waterflood	3 449	525	440	0	**964**	15	13	-	**28**
Polymer/ASP	8	2	1		**3**	25	13		**38**
Solvent flood	978	264	165	120	**549**	27	17	12	**56**
Gas flood	124	36	10	0	**46**	29	8	-	**37**
Heavy									
Primary depletion	1 649	190	0	0	**190**	12	-	-	**12**
Polymer/ASP	36	4	9		**13**	11	25		**36**
Waterflood	669	86	90	0	**176**	13	13	-	**26**
Total	**11 245**	**1 994**	**715**	**120**	**2 830**	**18**			**25**
Percentage of total initial established reserves		71%	25%	4%	**100%**				

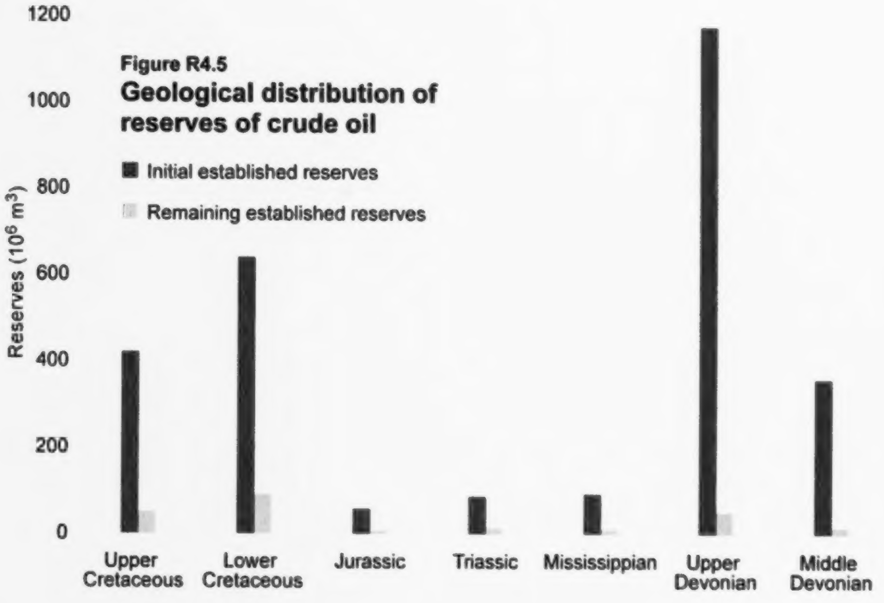


Figure R4.5
Geological distribution of reserves of crude oil

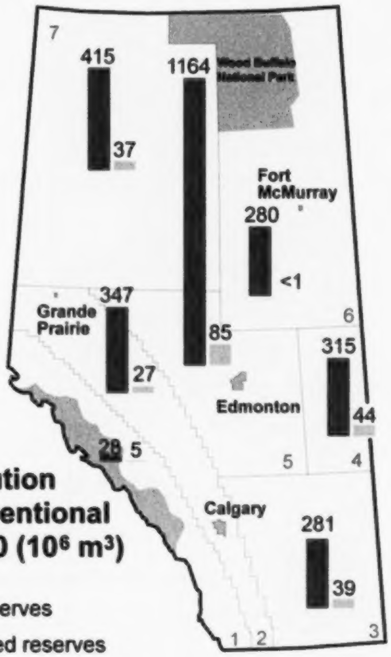


Figure R4.6
Regional distribution of Alberta's conventional oil reserves, 2010 (10^6 m^3)

■ Initial established reserves
▨ Remaining established reserves

4.1.3.4 Oil Reserves Methodology

The process of quantifying reserves is governed by many geological, engineering, and economic considerations. Initially there is higher uncertainty in the reserves estimates, but this uncertainty decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. The earliest reserves estimates are usually based on volumetric estimation. An estimate of bulk rock volume is based on net pay isopach maps derived primarily from geological evaluation of well log data. This is combined with data gathered on rock properties, such as porosity and water saturation, to determine oil in place at reservoir conditions. Areal assignments for new single-well oil pools range from 64 hectares (ha) for light-medium oil producing from regionally correlatable geologic units to 32 ha or less for heavy oil pools and small reef structures.

Converting volume in place to standard conditions at the surface requires applying oil shrinkage data obtained from pressure, volume, and temperature (PVT) analysis. A recovery factor is applied to the in-place volume to yield recoverable reserves. Oil recovery factors vary depending on oil viscosity, rock permeability, drilling density, rock wettability, reservoir heterogeneity, and reservoir drive mechanism. Recoveries range from 5 per cent in heavy oils to over 50 per cent in light-medium oils producing from highly permeable reefs with full pressure support from an active underlying aquifer. Provincially, 25 per cent of the in-place resource is expected to be recovered.

Once there are sufficient pressure and production data, material balance or production decline methods can be used as an alternative to volumetric estimation to determine in-place resources. Analysis by material balance is seldom used as it requires good pressure and PVT data. Production decline analysis is the primary method for determining recoverable reserves. When combined with a volumetric estimate of the in-place resource, it also provides a realistic estimate of the pool's recovery efficiency.

Secondary recovery techniques using artificial means of adding energy to a reservoir by water or gas injection can considerably increase oil recoveries. Less common tertiary recovery techniques may be applied by injecting fluids that are miscible with the reservoir oil at high pressures. This improves recovery efficiency by reducing the residual oil saturation at abandonment. However, irregularities in rock quality can lead to channelling, which causes low sweep efficiency and bypass of oil in some areas in the pool.

Incremental recovery over primary depletion is estimated for pools approved for waterflood and is displayed separately in the reserves database. To accommodate the Alberta government's royalty incentive programs, incremental recovery over an estimated base-case waterflood recovery is determined for tertiary schemes. Typically a base-case waterflood recovery is estimated even in cases where no waterflood was implemented before the solvent flood.

Reserves numbers published by the ERCB represent estimates for in-place, recoverable reserves, and recovery factors based on the most reasonable interpretation of available information from volumetric, production decline, and material balance methods.

4.1.4 Ultimate Potential

The ultimate potential of conventional crude oil was estimated by the ERCB in 1994 to be 3130 10^6 m^3, reflecting its estimate of geological prospects at that time. It does not include potential oil from very low permeability reservoirs, referred to by industry as "tight oil," which is now starting to be exploited using horizontal, multistage fracturing technology. **Figure R4.7** illustrates the historical decline in remaining established reserves relative to cumulative oil production. Extrapolation of the decline suggests that the ERCB's estimate of ultimate potential may be low.

Figure R4.8 shows Alberta's historical and forecast growth of initial established reserves. As of December 31, 2010, approximately 83 per cent of the estimated ultimate potential for conventional crude oil has been produced. To date, industry has discovered 90 per cent of the ultimate potential, leaving 10 per cent yet to be discovered, which when added to the remaining established reserves leaves 537 10^6 m^3 (3.4 billion barrels) of conventional crude oil available for future production.

The ERCB estimates that there are 300 10^6 m^3 of reserves yet to be discovered, which at current rates of reserves growth will require over 15 years to find and develop. The discovery of new pools and the development of existing pools will also continue to add new reserves and associated production each year.

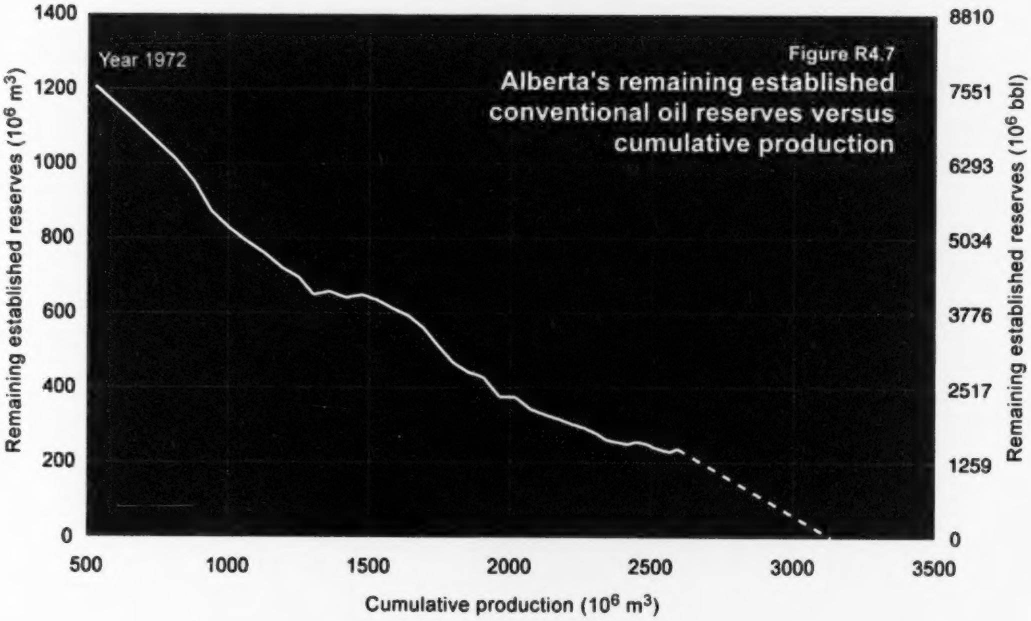


Figure R4.7
Alberta's remaining established conventional oil reserves versus cumulative production

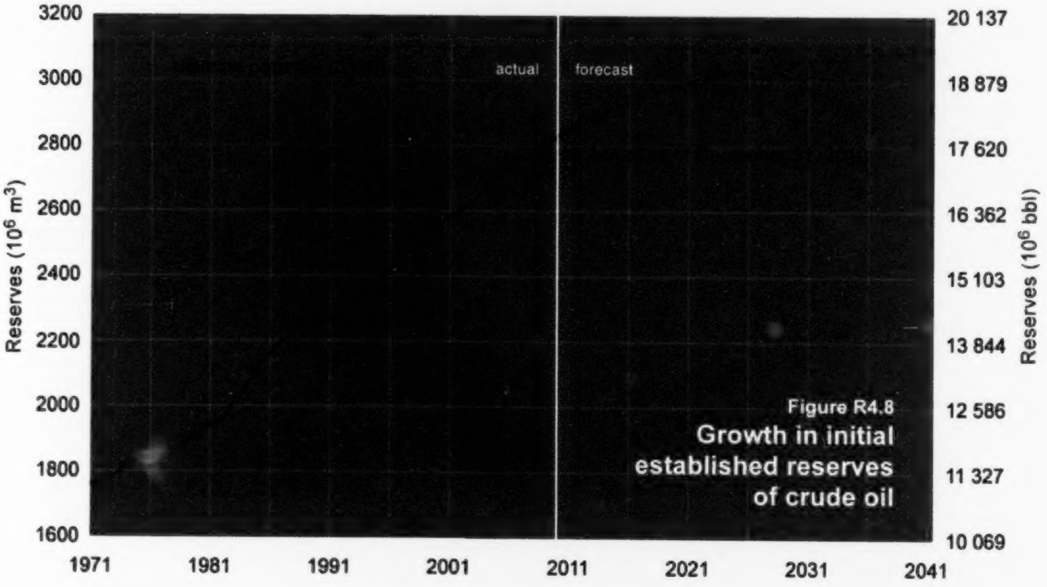


Figure R4.8
Growth in initial established reserves of crude oil

4.2 Supply of and Demand for Crude Oil

In projecting crude oil production, the ERCB considers two components: expected crude oil production from existing wells at year-end and expected production from new wells. Total forecast production of crude oil is the sum of these two components. Demand for crude oil in Alberta is based on provincial refinery capacity and use. Alberta crude oil supply in excess of Alberta demand is marketed outside the province.

4.2.1 Crude Oil Production—2010

Since the early 1970s, production of Alberta light-medium and heavy crude oil has been on a downward trend. This was certainly evident in 2009 as the oil industry reduced its upstream activities due to a continuation of low crude oil prices and weakened economic conditions that began in 2008. In 2010, light-medium crude oil did not continue along the same downward trend as a result of increased drilling activity and application of multistage fracturing technology. This new technology enhances horizontal drilling efficiency in low permeability reservoirs. Total crude oil production declined by only 0.4 per cent in 2010 to 73.0 10^3 m^3/d from 73.3 10^3 m^3/d.[1] Compared to the 8.6 per cent decline from 2008 to 2009, this is considerably lower than the 5-year average decline rate of 4.2 per cent. Light-medium crude oil production increased in 2010 by 0.2 10^3 m^3/d from its 2009 level to 50.7 10^3 m^3/d, reversing the declining trend. Heavy crude oil production declined slightly, by 1.9 per cent to 22.3 10^3 m^3/d.

4.2.1.1 Drilling Activity

In 2010, 2308 successful oil wells were drilled, a substantial increase of 143 per cent from 2009.[2] The last time Alberta experienced this high level of drilling was in 2005. **Figure S4.1** shows the number of successful oil wells drilled in Alberta in 2009 and 2010 by PSAC geographical area. Most oil drilling in 2010 (about 88 per cent) was development drilling. As shown in the figure, all areas of the province in which drilling activity occurred, in particular PSAC Areas 2 and 5, experienced substantial increases over last year's levels, except for PSAC 6, where fewer wells were drilled.

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[1] Unrounded production numbers were used to calculate per cent change in this section. Per cent change may be slightly different using rounded production numbers.

[2] Although the success ratio for conventional crude oil wells cannot be determined separately from all other drilling activity (excluding oil sands evaluation wells), less than 1 per cent of all development wells and less than 13 per cent of all exploratory wells drilled in 2010 were abandoned at the time of drilling. Overall, less than 3 per cent of all wells drilled in 2010 were abandoned at the time of drilling.

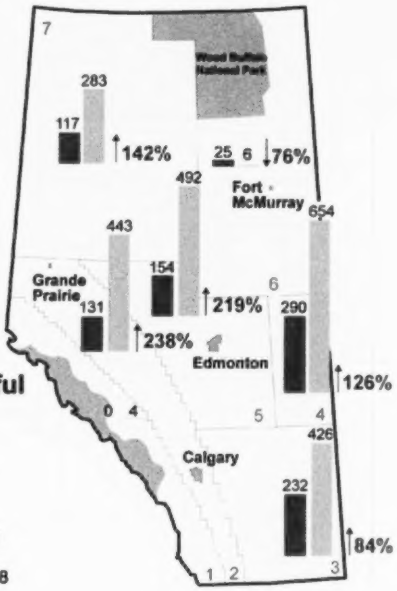
7
Wood Buffalo National Park
283
117
↑142%
25
6
↓76%
492
Fort McMurray
654
443
154
Grande Prairie
131
6
↑219%
290
↑238%
Edmonton
↑126%
0
4
5
4
426
Calgary
232
↑84%
1
2
3

Figure S4.1
Alberta successful oil well drilling by PSAC area

■ 2009 wells drilled = 949

░ 2010 wells drilled = 2308

Figure S4.2 depicts the distribution of new crude oil wells placed on production, and **Figure S4.3** shows the initial operating day rates of new wells in 2010. The number of oil wells placed on production in a given year generally tends to follow crude oil well drilling activity, as most wells are put on production shortly after being drilled. In 2010, wells placed on production more than doubled, from 1046 in 2009 to 2148. This increase corresponds to the increase seen in the number of successful oil wells drilled.

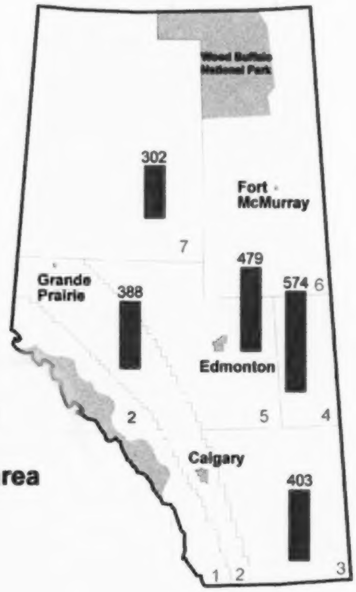
Wood Buffalo National Park
302
Fort McMurray
7
479
574
6
Grande Prairie
388
Edmonton
2
5
4
Calgary
403
1
2
3

Figure S4.2
Oil wells placed on production, 2010, by PSAC area

Total wells = 2148

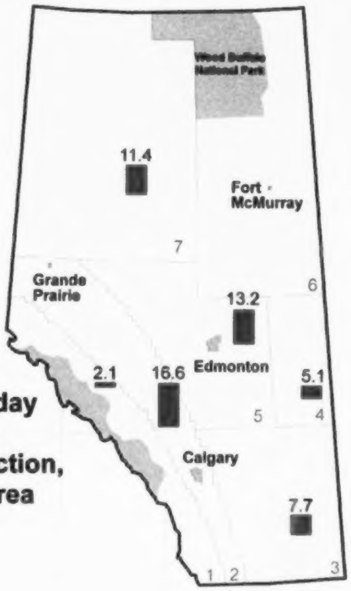
Wood Buffalo National Park
11.4
Fort McMurray
7
Grande Prairie
6
13.2
2.1
16.6
Edmonton
5.1
5
4
Calgary
7.7
1
2
3

Figure S4.3
Initial operating day rates of oil wells placed on production, 2010, by PSAC area (m^3/day)

4.2.1.2 Production Characteristics

Historical oil production by PSAC area is illustrated in **Figure S4.4**. In 2010, PSAC Areas 1, 2, 5, 6, and 7 experienced increases in production when compared to 2009, ranging from a 0.5 per cent increase in PSAC Area 7 to a 9.4 per cent increase in PSAC Area 1. However, PSAC Areas 3 and 4 reported declines in production of 2.8 and 3.7 per cent, respectively.

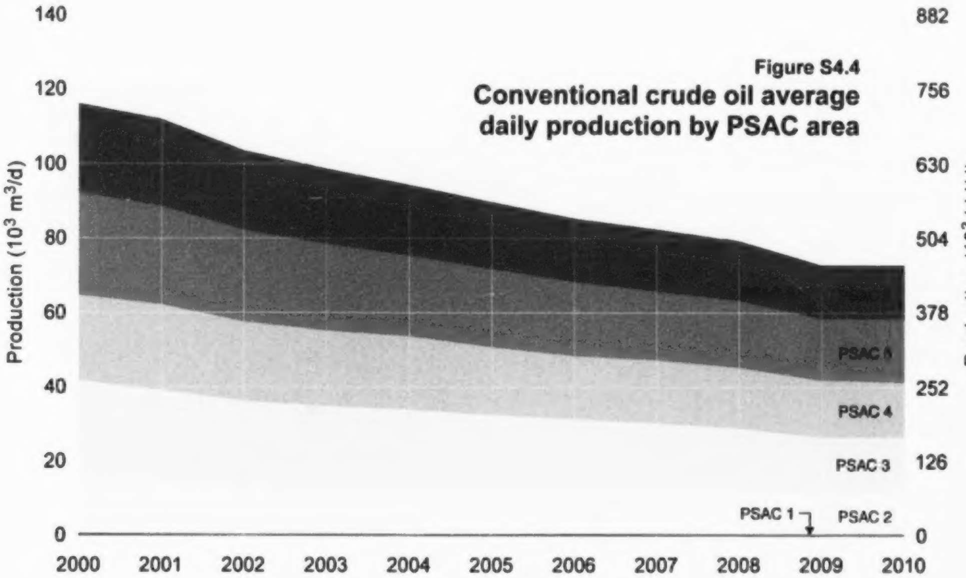

Figure S4.4
Conventional crude oil average daily production by PSAC area

Annual ERCB drilling statistics indicate that the number of wells producing oil has increased over time from 9100 in 1970 to 38 886 in 2010. The average annual production rate of oil producing wells, however, has been on decline since 1973 with the exception of 2010. The average daily production rate per well in 1973 was 23 m^3/d. This average declined to 5.5 m^3/d by 1991 and reached levels of 1.9 m^3/d by 2009. In 2010, the average daily production rate per well did not continue to decline but remained steady at 1.9 m^3/d as a result of increased drilling activity and, in particular, the increased use of multistage fracturing technology in horizontal wells. Early analysis indicates that initial production rates are higher for these wells than for vertical and conventional horizontal well types.

Figure S4.5 shows that on average total crude oil production has been on decline up to and including 2009 while the number of wells producing crude oil had been increasing. As noted earlier, production remained relatively flat in 2010 when compared to 2009 volumes due to increased drilling activity and use of multistage fracturing technology.

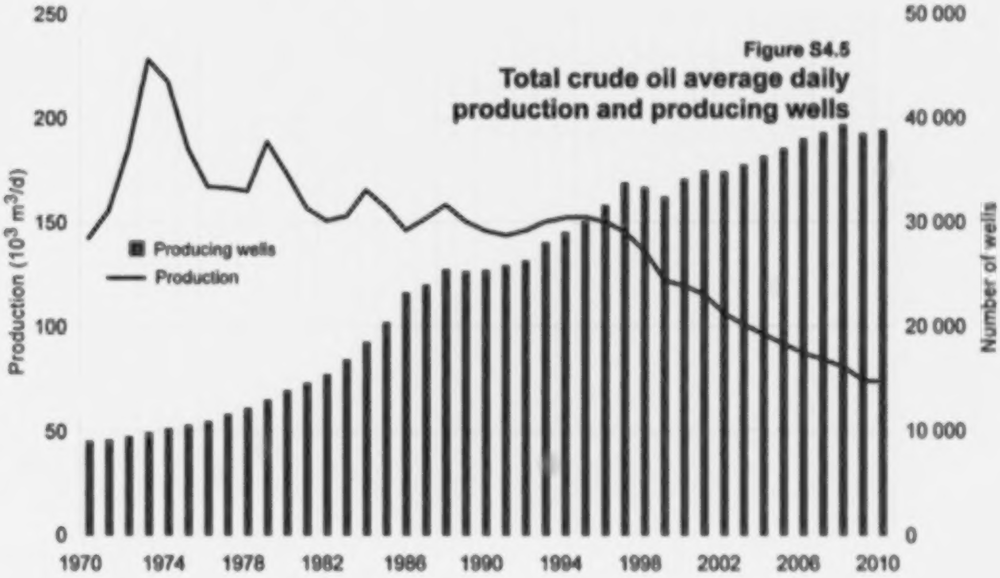

Figure S4.5

Total crude oil average daily production and producing wells

Of the 38 886 wells producing oil in 2010, about 2931 were classified as gas wells. Although these gas wells represented 7.5 per cent of wells that produced oil, they produced at an average rate of only 0.2 m^3/d and accounted for less than 1 per cent of total production. Also included were about 4850 producing horizontal oil wells that accounted for 12 per cent of producing oil wells but contributed about 23 per cent to the total crude oil production because of the higher average production rate per well.

Figure S4.6 depicts producing oil wells and the average daily production rates of those wells by region in 2010. The average well productivity of crude oil producing wells in 2010 was 2.0 m^3/d. Roughly 44 per cent of crude oil producing wells produced at rates less than 1 m^3/d per well, a characteristic seen in maturing basins. In 2010, the 15 800 oil wells in this category operated at an average rate of 0.6 m^3/d and accounted for only 11 per cent of the total crude oil produced. **Figure S4.7** shows the distribution of crude oil producing wells (including horizontal oil wells) based on their average production rates in 2010.

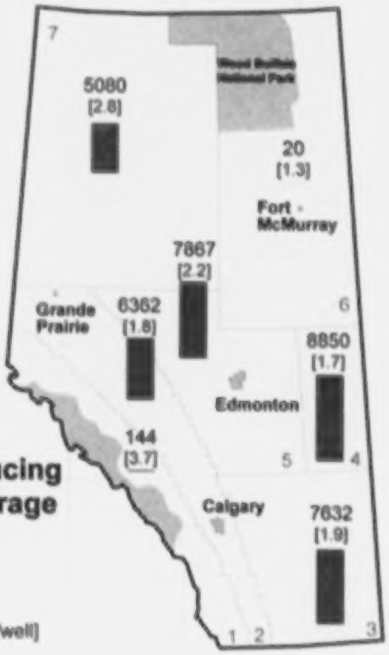

Figure S4.6
Number of producing oil wells and average day rates, 2010, by PSAC area
Total wells = 35 955
Average day rates [m^3/day/well]

In 2010, 1023 new horizontal oil wells (including those using multistage fracturing technology) were brought on production, a 276 per cent increase from 2009, raising the total number of horizontal wells to 4850. Initial production from horizontal wells drilled in the past ten years peaked in 2002 at an average rate per well of 9.2 m^3/d, and the initial production rate per well of new horizontal wells in 2010 is 6.5 m^3/d. New horizontal wells drilled in 2010 have higher initial production rates than the 6.1 m^3/d reported last year. The average initial rate per well for vertical wells is 3.6 m^3/d.

Crude oil production from existing wells placed on production from 2000 to 2010 is depicted in **Figure S4.8**. This figure illustrates that about 33 per cent of crude oil production in 2010 represents wells placed on production in the last five years.

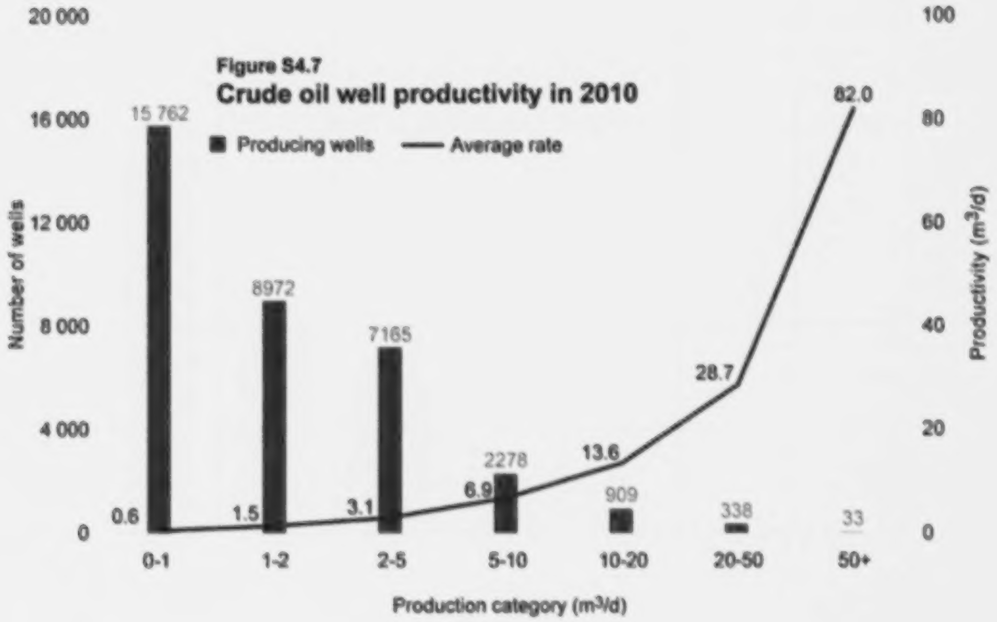

Figure S4.7

Crude oil well productivity in 2010

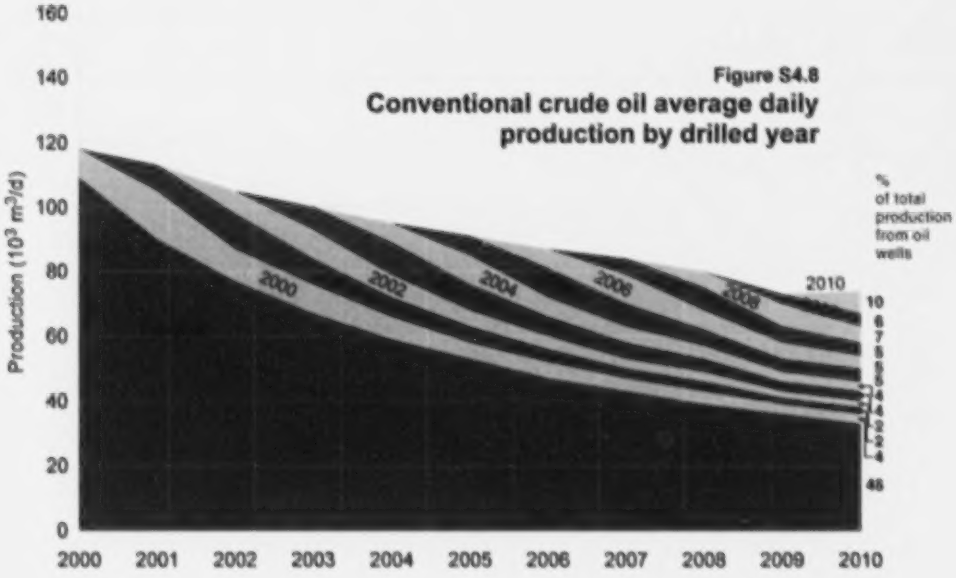

Figure S4.8

Conventional crude oil average daily production by drilled year

4.2.2 Crude Oil Production—Forecast

To project crude oil production over the forecast period, the ERCB has categorized wells into the following three groups: conventional vertical wells, conventional horizontal well and multistage fractured horizontal wells. The last category of wells is new to the provincial forecasts. Production from these wells has been forecast using the limited information available and, therefore, is less certain than the projection of production for the other categories. More information will become available over time and will be incorporated into future analysis and forecasts.

To forecast production from each category, production from existing and new wells drilled each year has been analyzed. The number of wells drilled and the average productivity of the wells in each category are the main factors used to project oil volumes over the forecast period.

4.2.2.1 Vertical Wells

To project crude oil production from vertical wells drilled before 2011, the ERCB assumes the following:

- Production from existing vertical wells in 2011 will be 49.9 10^3 m^3/d.
- Production from existing wells will decline by 14.0 per cent per year.

Over the forecast period, production of crude oil from existing vertical wells is expected to decline from 49.9 10^3 m^3/d to 12.8 10^3 m^3/d by 2020.

Total production from new vertical wells is also a function of the number of new wells that will be drilled successfully, their initial production rate, and their expected average decline rate. The forecast for production from new vertical wells acknowledges industry's continued interest in drilling for oil using conventional technology.

To project crude oil production from new vertical wells, the ERCB made the following assumptions:

- The number of new vertical oil wells placed on production is projected to be 1100 in 2011 and expected to remain at this level over the forecast period. This well count is relatively low and reflects the view that many new wells will be horizontal wells using multistage fracturing technology.
- The average initial production rate for new vertical wells is projected to be 3.5 m^3/d/well and expected to decrease to 2.0 m^3/d/well by the end of the forecast period.
- Production from new wells will decline at a rate of 25 per cent the first year, 22 per cent the second year, 21 per cent the third year, 19 per cent the fourth year, and 16 per cent over the rest of the forecast period. **Figure S4.9** illustrates the crude oil production from vertical wells.

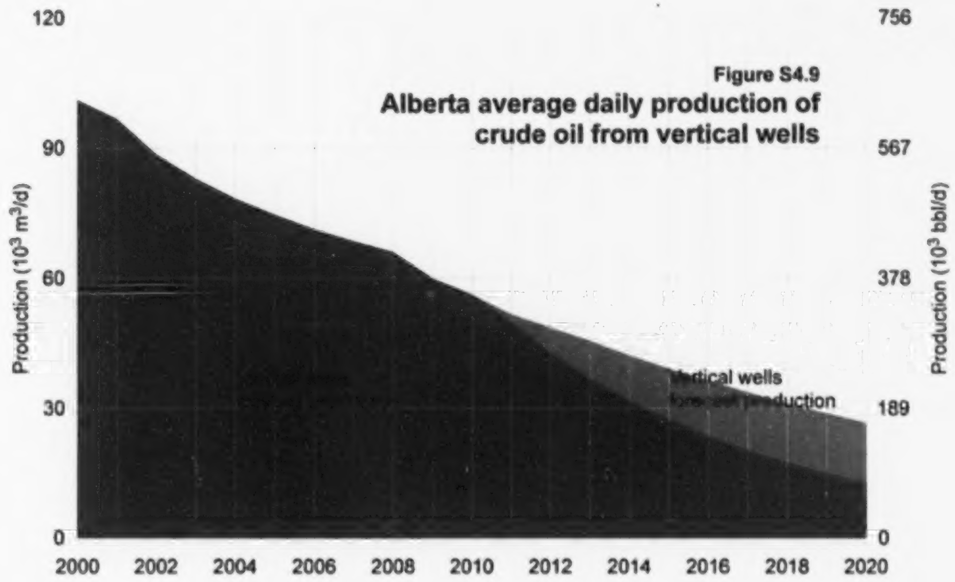
Figure S4.9
Alberta average daily production of crude oil from vertical wells

4.2.2.2 Conventional Horizontal Wells

A methodology similar to that used for vertical wells is used to project crude oil production from conventional horizontal wells. Potential crude oil production from existing and new wells is combined to project total production in this category of wells over the forecast period.

To project crude oil production from conventional horizontal wells drilled before 2011, the ERCB assumes the following:

- Production from existing wells in 2011 will be 11.9 10^3 m^3/d.
- Production from existing wells will decline at a rate of 15.0 per cent per year.

Over the forecast period, production of crude oil from existing conventional horizontal wells is expected to decline from 11.9 10^3 m^3/d in 2011 to 2.8 10^3 m^3/d by 2020.

The number of new conventional horizontal oil wells placed on production is projected to increase from 277 in 2010 to 500 in 2013, declining to 400 in 2014 and remaining at this level for the remainder of the forecast period.

Total production from new conventional horizontal wells is also a function of the initial production rate of new wells and the average decline rate expected for these wells. The average initial production rate for new conventional horizontal wells is projected to be 6.0 m^3/d/well in 2011 and will decrease to 4.5 m^3/d/well by the year 2020.

Production from new wells will decline at a rate of 39 per cent the first year, 27 per cent the second year, 20 per cent the third year, and 15 per cent over the remaining forecast period. **Figure S4.10** illustrates the crude oil production from conventional horizontal wells.

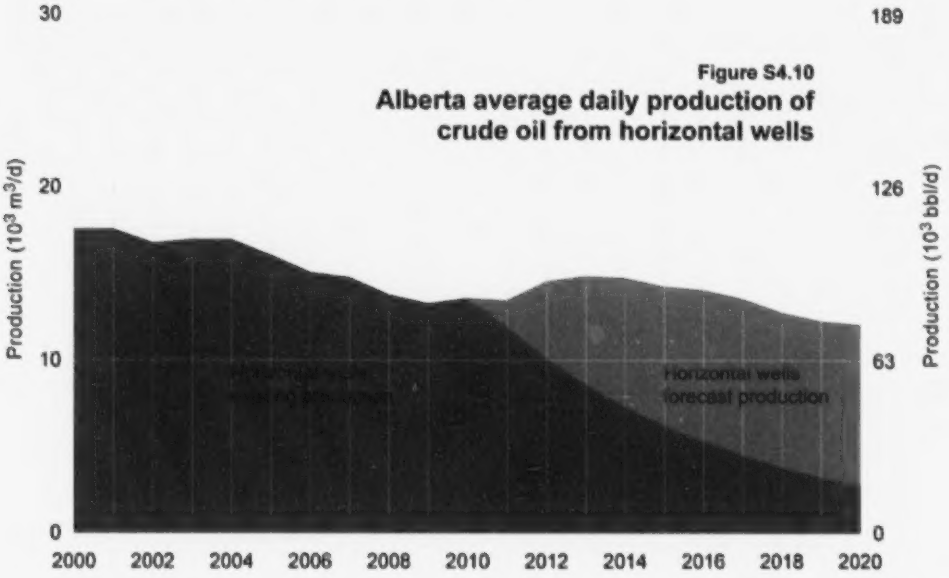

Figure S4.10
Alberta average daily production of crude oil from horizontal wells

4.2.2.3 Multistage Fractured Horizontal Wells

Since 2008, multistage fracturing techniques have been used in targeting the Cardium tight oil and other emerging plays and reserves that have been unrecovered in major pools in Alberta. Multistage fractured horizontal wells have been used successfully to unlock the Bakken tight oil play in North Dakota and southeastern Saskatchewan for a number of years.

With limited reliable data on multistage fractured horizontal wells and their performance over the past three years, the ERCB has attempted to provide a reasonable forecast on drilling activity and production rates from these wells. To forecast crude oil production from these wells, the same methodology that was used to project crude oil production from conventional vertical and horizontal wells was used. Potential crude oil production from existing and new wells is combined to project total production from multistage fractured horizontal wells over the forecast period.

To project crude oil production from multistage horizontal fractured wells drilled prior to 2011, the ERCB has assumed the following:

- Production from existing wells in 2011 will be 2.5 10^3 m^3/d.

- Production from existing wells will decline at a rate of 50 per cent per year in 2011, 35 per cent in 2012, 20 per cent in 2013, and 15 per cent from 2014 to the end of the forecast period.

Over the forecast period, production of crude oil from existing multistage fractured horizontal wells is expected to decline from 2.5 10^3 m^3/d in 2011 to 0.4 10^3 m^3/d by 2020.

The number of new multistage fractured horizontal oil wells placed on production is projected to increase from 745 in 2010 to 1200 from 2011 to 2013. This number is expected to decline to 1000 in 2014 and remain at this level for the remainder of the forecast period. This projection considers the option that companies have in diversifying their drilling activity with natural gas, given the expected increase in gas demand and price over this same period, but may prove to be conservative based on the crude oil opportunities present in the basin. **Figure S4.11** illustrates the crude oil production from multistage fractured horizontal wells.

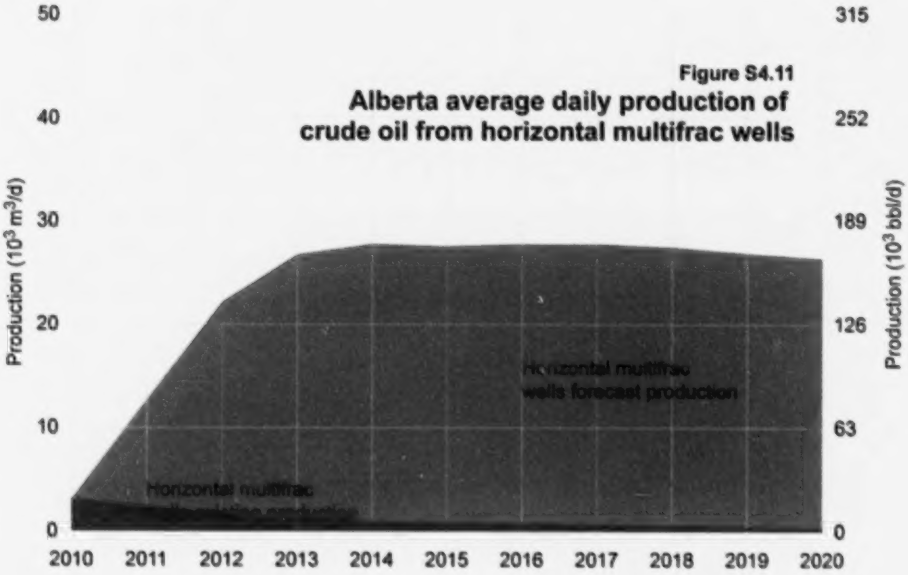
Figure S4.11
Alberta average daily production of crude oil from horizontal multifrac wells

The projected total crude oil production, which comprises production from both existing wells and new vertical, horizontal, and multistage fractured horizontal wells, is illustrated in **Figure S4.12**.

Figure S4.13 illustrates the split for light-medium and heavy crude oil. Light-medium crude oil production is expected to decline from 50.7 10^3 m^3/d in 2010 to 48.1 10^3 m^3/d in 2020. Over the forecast period, heavy crude production is also expected to decrease, from 22.3 10^3 m^3/d in 2010 to 16.9 10^3 m^3/d by the end of the forecast period. **Figure S4.13** also illustrates that by 2020, heavy crude oil production will constitute a lesser portion of total conventional crude oil production in Alberta (26 per cent) compared to 2010 (31 per cent).This change from last year's report is attributed to the increased use of multistage fracturing technology in light-medium density plays to recover crude oil.

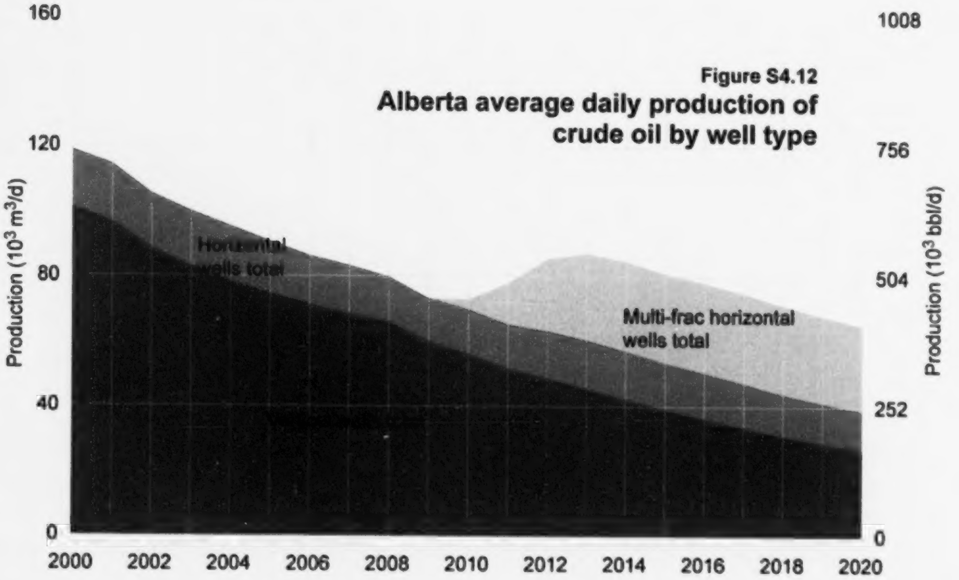
Figure S4.12
Alberta average daily production of crude oil by well type

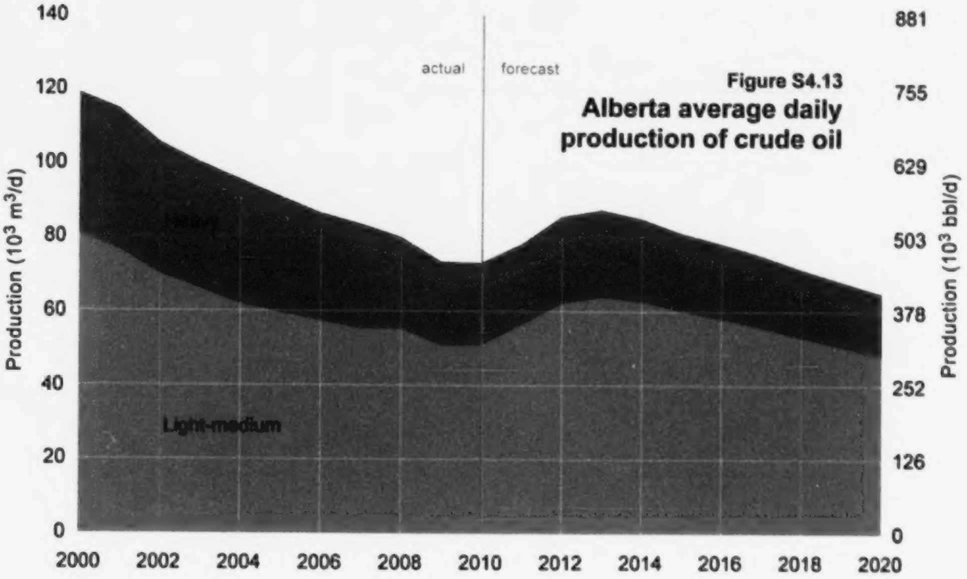
Figure S4.13
Alberta average daily production of crude oil

This production forecast assumes that crude oil production will increase by 6.8 per cent in 2011, in contrast to the slight decline of 0.4 per cent in 2010, primarily due to the expected increase in drilling activity and use of multistage fracturing technology on horizontal wells. Crude oil production is expected to peak in 2013 and begin declining at an average decline rate of 4 per cent over the remainder of the forecast period as production from increased wells drilled and wells drilled with new technology somewhat offset declining production from existing wells.

The combined forecasts for existing and future wells indicate that total crude oil production will decline from 73.0 10^3 m^3/d in 2010 to 65.0 10^3 m^3/d in 2020. Based on this projection, Alberta will have produced about 92 per cent of the estimated ultimate potential of 3130 10^6 m^3 by 2020. As discussed earlier, if the use of multistage completion technology in horizontal wells becomes more widespread in Alberta, the forecast may prove to be conservative.

Figure S4.14 illustrates the annual number of new wells expected to be placed on production from 2011 to 2020 and includes the forecast for WTI crude oil price. As the price of crude oil increases, oil drilling activity is expected to remain strong.

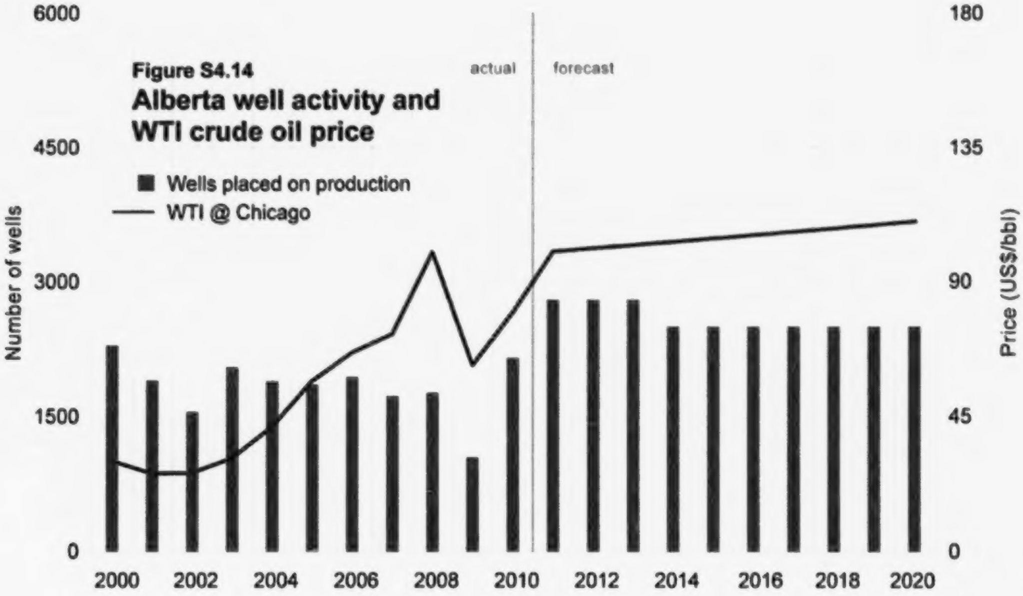

Figure S4.14

Alberta well activity and WTI crude oil price

4.2.3 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with synthetic crude oil (SCO), bitumen, and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). The key determinants of crude oil feedstock requirements for Alberta refineries are domestic demand for RPPs, shipments to other western Canadian provinces, exports to the United States, and competition from other feedstocks. Since Alberta is a "swing" supplier of RPPs in western Canada, a refinery closure or expansion in this market may have a significant impact on the demand for Alberta RPPs and on Alberta crude oil feedstock requirements.

In 2010, Alberta refineries, with a total inlet capacity of 75.5 10^3 m^3/d of crude oil and equivalent, processed 17.3 10^3 m^3/d of conventional crude oil. This is the same volume of crude oil processed in 2009. Refinery demand for conventional crude oil in Alberta declined substantially between 2008 and 2009 as a result of Suncor's (formerly Petro-Canada's) Edmonton refinery fully replacing light-medium crude oil with SCO and nonupgraded bitumen in 2009. This resulted in conventional crude oil accounting for roughly 28 per cent of the total crude oil and equivalent feedstock to Alberta refineries in 2010, 3 per cent less than in 2009.

SCO, bitumen, and pentanes plus constitute the remaining feedstock processed through Alberta refineries. **Figure S4.15** illustrates the current capacity and location of refineries in Alberta. Additional crude oil refining capacity is not expected over the forecast period.

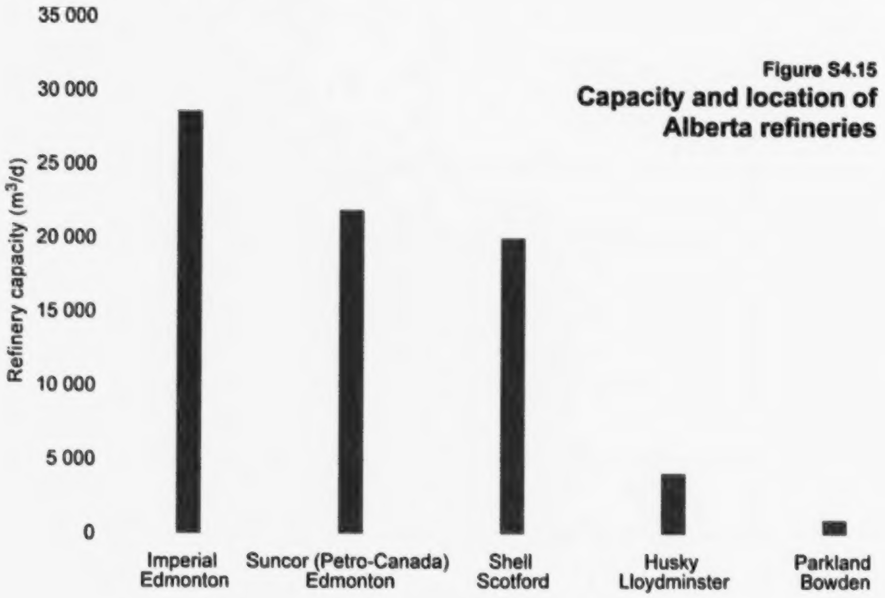

Figure S4.15
Capacity and location of Alberta refineries

In 2010, the refinery utilization of capacity was about 84 per cent, up from 73 per cent in 2009. Refinery operations in 2009 were severely affected by planned maintenance turnarounds at all three Edmonton refineries in addition to unplanned operation outages. In 2010, refinery operations in the Edmonton area were affected by planned maintenance at Imperial's Strathcona refinery in May and Suncor's Edmonton refinery in October. Suncor's refinery also experienced a partial shutdown mid-March due to mechanical problems. The forecast assumes that total crude oil use in Alberta's refineries will increase to 20 10^3 m^3/d in 2010, based on an increased utilization rate of 90 per cent and remain at this level for the remainder of the forecast period.

Shipments of crude oil outside of Alberta, depicted in **Figure S4.16**, amounted to 76 per cent of total production in 2010.

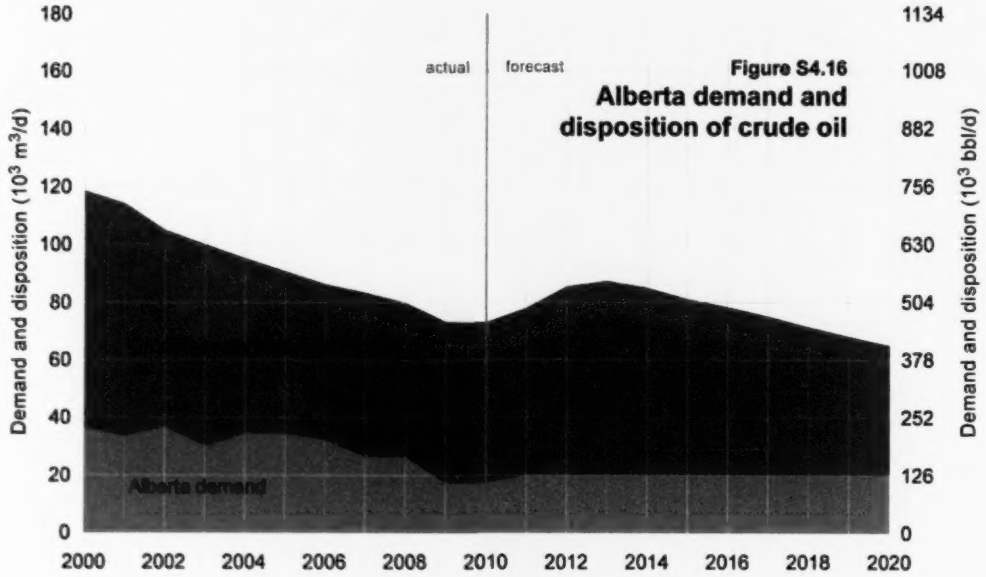

Figure S4.16
Alberta demand and disposition of crude oil

The ERCB expects that by 2020 about 69 per cent of production will be removed from the province, due to the decline expected in Alberta light-medium and heavy crude oil production over time.

5 NATURAL GAS

HIGHLIGHTS

Alberta's remaining established conventional natural gas reserves decreased by 2.9 per cent in 2010, to 1025 billion cubic metres.

Reserve additions as a result of new drilling replaced 46 per cent of conventional gas production.

CBM initial reserves increased by 12 per cent.

Marketable gas production declined by 5.6 per cent in 2010, compared with a 7.9 per cent decline in 2009.

There were 3099 new conventional gas well connections and 1085 CBM and CBM hybrid connections in 2010, down 19 per cent and 38 per cent, respectively, from 2009.

Raw natural gas consists mostly of methane and other hydrocarbon gases, but it also contains other nonhydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulphide (H_2S). These impurities typically make up less than 10 per cent of raw natural gas. The estimated average composition of the hydrocarbon component without impurities is about 92 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. Hydrocarbon components that exist in gaseous form in the reservoir, but which condense and are recovered as a liquid at the surface, may be reported as gas equivalent or condensate. Such liquids, as well as ethane which is primarily produced as a gas, are referred to as natural gas liquids (NGLs) and reported in Section 6. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume, as described in Section 5.1.9.

In this section, natural gas volumes are referred to as either the actual metered volume with the combined heating value of the hydrocarbon components present in the gas (i.e., "as is") or the volume, at standard conditions, of 37.4 megajoules per cubic metre (MJ/m^3). The average heat content of produced conventional natural gas leaving field plants is estimated to be 38.9 MJ/m^3. This compares with a heat content of about 37.0 MJ/m^3 for coalbed methane (CBM), which consists mostly of methane.

In this year's report, the conventional natural gas and unconventional natural gas sections are combined. Unconventional gas is described in this section as CBM and shale gas. Conventional and unconventional gases are discussed separately within this section where applicable.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary of Natural Gas

As of December 31, 2010, the ERCB estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 1025 billion (10^9) m^3, with a total energy content of about 40 exajoules. This decrease of 30.6 10^9 m^3 since December 31, 2009, is a result of all reserves additions less production during 2010. These reserves include 30.2 10^9 m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.1 per cent reduction in the average heating value from 38.9 MJ/m^3 to 37.3 MJ/m^3 for gas downstream of straddle plants. Details of the changes in marketable reserves during 2010 are shown in **Table 5.1**. Total

5 NATURAL GAS

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Table 5.1 Reserve and production changes in marketable conventional gas (10^9 m^3)

	Gross heating value (MJ/m^3)	2010 volume	2009 volume	Change
Initial established reserves		5 213.5	5 130.7	+82.8
Cumulative production		4 188.4	4 075.0	+113.4[a]
Remaining established reserves downstream of field plants				
"as is"	38.9	1 025.1	1 055.7	-30.6
at standard gross heating value	37.4	1 065.7	1 098.0	
Minus liquids removed at straddle plants		30.2	31.3	-1.1[b]
Remaining established reserves				
"as is"	37.3	994.9[b] (35.3Tcf)[c]	1 024.5[b] (36.4 Tcf)[c]	-29.6[b]
at standard gross heating value	37.4	991.4	1 021.0	
Annual production	37.4	107.3[d]	113.9	-6.6

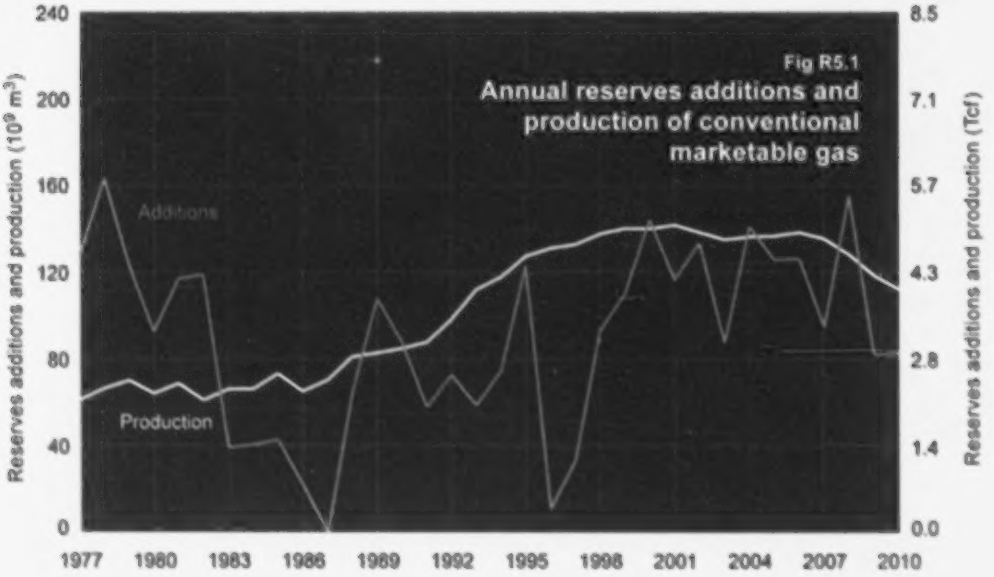
[a] May differ from annual production

[b] Any discrepancies are due to rounding

[c] Tcf – trillion cubic feet

[d] Does not include conventional gas from ERCB-defined unconventional wells

Annual reserves additions and natural gas production since 1977 are depicted in **Figure R5.1**. It shows that since 1983, reserves additions have generally not kept pace with production. As illustrated in **Figure R5.2**, Alberta's remaining established reserves of marketable conventional gas have decreased by about 45 per cent since 1982.



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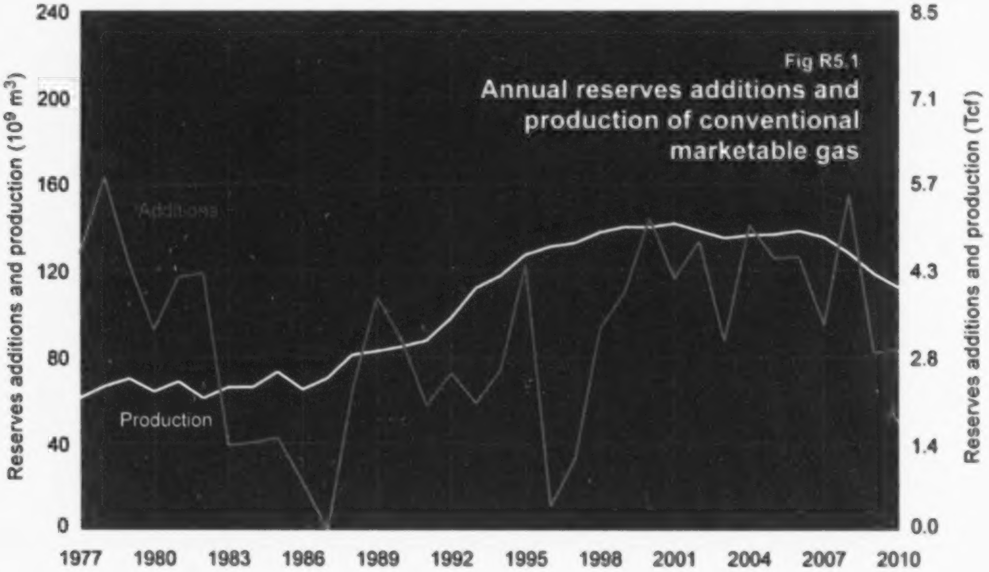

Fig R5.1

Annual reserves additions and production of conventional marketable gas

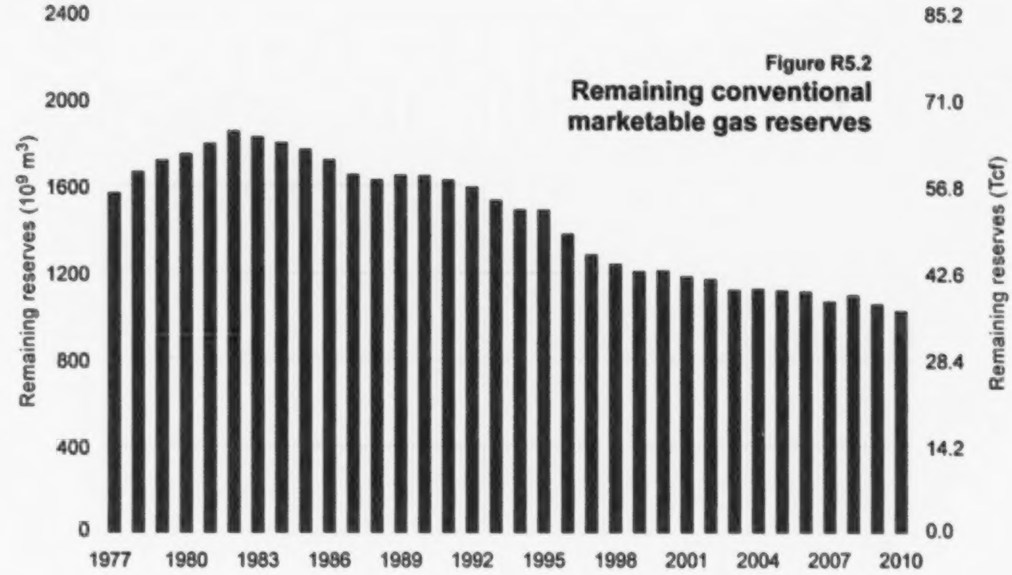
Figure R5.2
Remaining conventional marketable gas reserves

The ERCB estimates the initial established reserves of CBM to be 100.5 10^9 m^3 as of December 31, 2010, an increase of 10.5 10^9 m^3 from 2009. This increase of 12 per cent is due to the re-evaluation of gas content and recovery factors. Remaining established reserves in 2010 are 67.6 10^9 m^3, up from 64.5 10^9 m^3 in 2009.

A summary of CBM reserves and production is shown in **Table 5.2**. In 2010, the annual production from all wells listed as CBM was 8.9 10^9 m^3. This volume represents the total contribution from CBM wells, including wells commingled with conventional gas.[1] The portion of production estimated to be attributed to only CBM is 7.4 10^9 m^3, as listed in **Table 5.2**.

Table 5.2 CBM reserve and production change highlights (10^9 m^3)

	2010	2009	Change
Initial established reserves	100.5	90.0	+10.5
Cumulative production	32.9	25.5	+7.4[a]
Remaining established reserves	67.6 (2.4 Tcf)[b]	64.5 (2.3 Tcf)[b]	+3.1
Annual production	7.4	6.5	+0.9

[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.

[b] Tcf - trillion cubic feet.

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[1] Wells commingled with conventional gas are defined as CBM hybrid wells.

5.1.2 In-Place Resource of Natural Gas

The ERCB estimates the total initial in-place resource of natural gas in Alberta to be 9513 10^9 m^3, consisting of 9211 10^9 m^3 of conventional natural gas and 301 10^9 m^3 of CBM. With conventional cumulative raw production of 4912 10^9 m^3, 4299 10^9 m^3 of this gas remains in the ground. CBM cumulative raw production is 33 10^9 m^3, and 268 10^9 m^3 remains in the ground. As of December 31, 2010, 4567 10^9 m^3 of natural gas remains unproduced in Alberta. With current technologies, 1270 10^9 m^3 is still expected to be produced.

A large-scale resource assessment by the ERCB of shale gas potential in Alberta is underway. It is anticipated that the resource potential of some of the formations will be completed in 2012. Several independent organizations have evaluated the resource potential of shale in the Western Canada Sedimentary Basin (WCSB), and the values of the estimates largely depend on the methodology, the formations used, and the extrapolation of data points to a large resource volume. Values range widely from less than a quarter to almost two orders of magnitude more than the initial in-place volume of conventional natural gas. Notwithstanding the large variability of the values, the scale of the estimates proclaims the considerable potential for shale gas to be added to the provincial resource base.

5.1.3 Established Reserves of Conventional Natural Gas

Figure R5.3 shows the breakdown of annual reserves changes into new pools, development of existing pools, and reassessment of reserves of existing pools from 2001 to 2010. The 82.8 10^9 m^3 increase in initial reserves for 2010 includes the addition of 24.3 10^9 m^3 attributed to new pools booked in 2010, 25.3 10^9 m^3 from the development of existing pools, and a net reassessment of 33.2 10^9 m^3 for existing

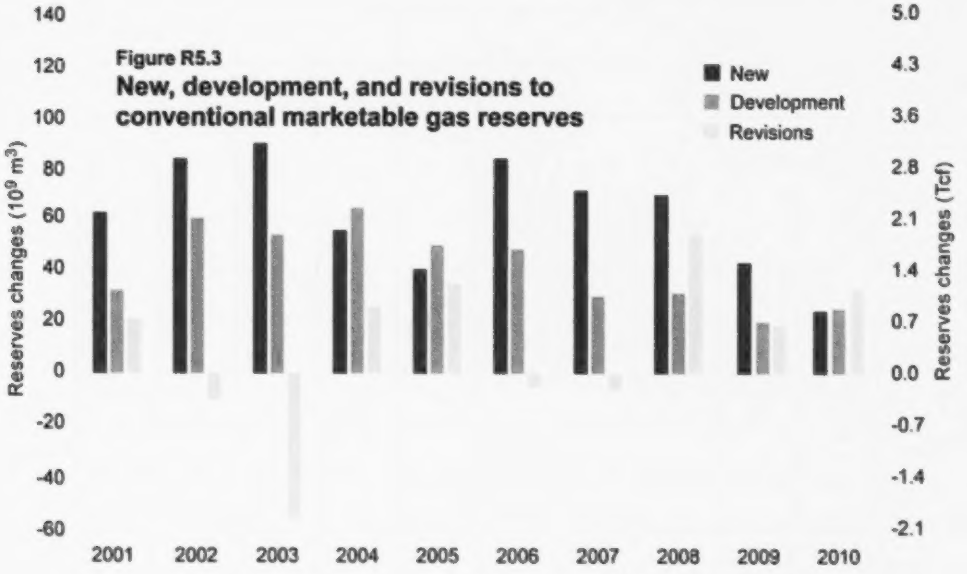
Figure R5.3
New, development, and revisions to conventional marketable gas reserves

pools. Reserves added through drilling (new plus development) totalled 49.6 10^9 m^3, replacing 46 per cent of Alberta's 2010 production. Historical reserves growth and production data since 1966 are shown in **Appendix B, Table B.4**.

During 2010, a review was done of pools that appeared to have reserves under- or overbooked based on their reserves-to-production ratios; another review was done of large pools that had not been evaluated for several years. Positive revisions to existing pools totalled 108.4 10^9 m^3, while negative revisions totalled 75.3 10^9 m^3. The major reserves changes are summarized below.

- The 20 pools with the largest changes listed in **Table 5.3** resulted in a net addition of 38.4 10^9 m^3. This increase in reserves was largely a result of infill drilling and completion of previously undeveloped zones.
- The review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in a reserves increase of 14.0 10^9 m^3.
- Several hundred pools were evaluated with low or high reserves life indices, resulting in an overall reserves increase of 6.9 10^9 m^3.

Figure R5.4 illustrates initial marketable gas reserves growth between 2009 and 2010 by area as defined by the Petroleum Services Association of Canada (PSAC). The most significant growth was in PSAC Area 2 (Foothills Front), which accounted for 51 per cent of the total annual increase for 2010. Some pools in Area 2 that contributed to this increase in reserves are the Ansell Commingled MFP9502, Harley Leduc D, Pembina Cardium, Sundance Commingled MFP9502, and Wapiti Commingled MFP9529, for a total reserves increase of 17.8 10^9 m^3.

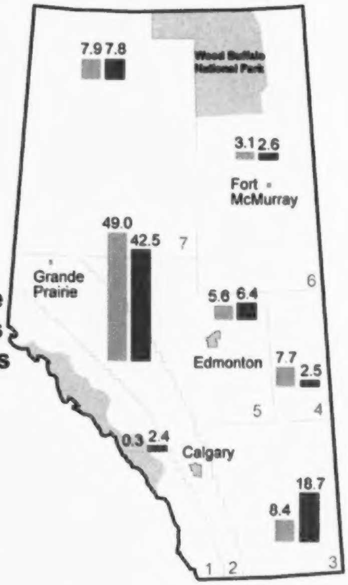

Figure R5.4
Initial marketable conventional gas reserves changes by PSAC area (10^9 m^3)

▨ 2009
Total = 82.0 10^9 m^3
■ 2010
Total = 82.8 10^9 m^3

Table 5.3 Major natural gas reserve changes, 2010

	Initial established reserves (10^6 m^3)		
Pool name	**2010**	**Change**	**Main reasons for change**
Ansell Commingled MFP9502[a]	30 258	+3 358	Re-evaluation of initial volume in place and recovery factor
Bantry Southeastern Alberta Gas System	37 778	+1 625	Development and re-evaluation of initial volume in place
Bashaw Commingled MFP9504	8 082	+1 442	Re-evaluation of initial volume in place and recovery factor
Cavalier Southeastern Alberta Gas System	2 813	+837	Development and re-evaluation of initial volume in place
Countess Southeastern Alberta Gas System	71 455	+2 180	Development and re-evaluation of initial volume in place
Elmworth Commingled MFP9513	58 635	+787	Re-evaluation of initial volume in place
Harley Leduc D	1 330	+1 248	Re-evaluation of initial volume in place and recovery factor
Kaybob South Commingled MFP9529	5 789	+1 669	Re-evaluation of initial volume in place
Kaybob South Commingled Pool 013	5 770	+1 197	Re-evaluation of initial volume in place
Lathom Southeastern Alberta Gas System	4 483	-855	Re-evaluation of initial volume in place
Leo Southeastern Alberta Gas System	1 269	+1 255	Re-evaluation of initial volume in place
Medicine Hat Southeastern Alberta Gas System	167 087	+3 785	Development and re-evaluation of initial volume in place
Oldman Commingled MFP9529	2 712	-1 110	Re-evaluation of initial volume in place and recovery factor
Pembina Cardium	25 222	+4 226	Re-evaluation of initial volume in place
Pouce Coupe South Commingled Pool 012	11 925	+1 299	Re-evaluation of initial volume in place
Red Rock Commingled MFP9529	13 387	+1 359	Re-evaluation of initial volume in place
Sundance Commingled MFP9502	18 835	+1 569	Re-evaluation of initial volume in place and recovery factor
Verger Southeastern Alberta Gas System	19 990	+2 287	Development and re-evaluation of initial volume in place
Wapiti Commingled MFP9529	54 077	+9 131	Re-evaluation of initial volume in place
Wintering Hills Southeastern Alberta Gas System	9 988	+1 100	Development and re-evaluation of initial volume in place

[a] MFP (multifield pool) is defined in Section 5.1.3.7

5.1.3.1 Distribution of Conventional Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in **Table 5.4**. Commingled pools are considered as one pool, whereas each field in a multifield pool is counted as a separate pool. The data shows that pools with reserves of 30 million (10^6) m^3 or less, while representing 73 per cent of all pools, contain only 12 per cent of the province's remaining marketable reserves. Similarly, pools with reserves greater than 1500 10^6 m^3, while representing only 1 per cent of all pools, contain 52 per cent of the remaining reserves.

Table 5.4 Distribution of natural gas reserves by pool size, 2010

Reserve range (10^6 m^3)	Pools #	Pools %	Initial established marketable reserves 10^9 m^3	Initial established marketable reserves %	Remaining established marketable reserves 10^9 m^3	Remaining established marketable reserves %
3000+	215	0.5	2 846	55	497	48
1501-3000	172	0.4	368	7	62	6
1001-1500	176	0.4	217	4	34	3
501-1000	527	1.2	363	7	53	5
101-500	3 456	7.7	714	14	137	13
31-100	7 825	17.4	411	8	122	12
Less than 31	32 666	72.5	294	6	120	12
Total	**45 037**	**100.0**	**5 214**	**100**	**1 025**	**100**

5.1.3.2 Geological Distribution of Conventional Natural Gas Reserves

The distribution of reserves by geological period is shown in **Figure R5.5**. The Upper and Lower Cretaceous period accounts for about 73 per cent of the province's remaining established reserves of marketable gas and is important as a future source of natural gas.

The geologic strata containing the largest remaining reserves are the Lower Cretaceous Mannville, with 37 per cent, the Upper Cretaceous Belly River, Milk River, and Medicine Hat, with 18 per cent, and the Mississippian Rundle, with 7 per cent. Together, these strata contain 62 per cent of the province's remaining established reserves.

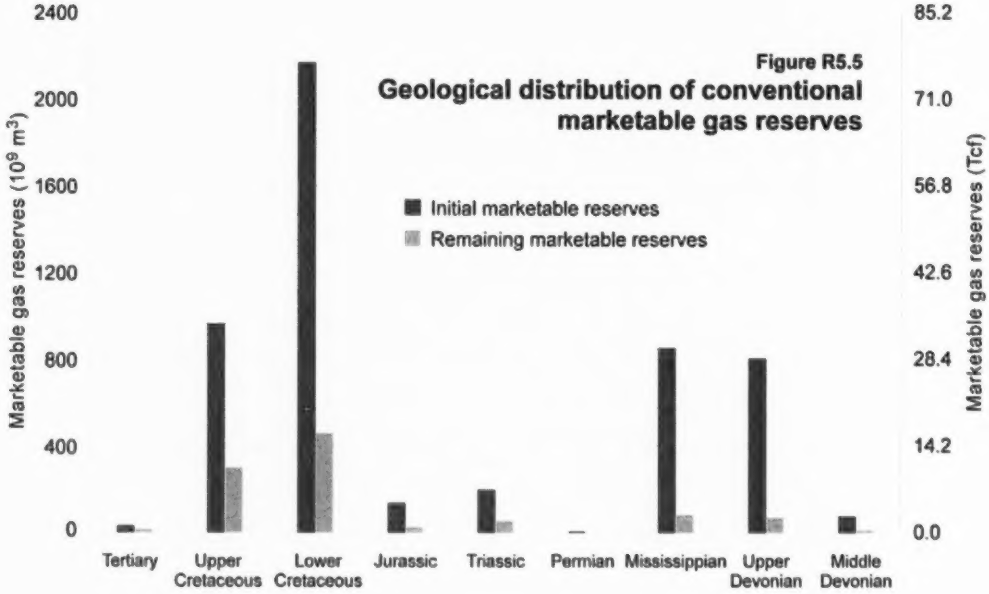
Figure R5.5
Geological distribution of conventional marketable gas reserves

5.1.3.3 Gas Commingling

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. As shown in **Table 5.5**, 25 per cent (14 358) of all gas pools in Alberta are commingled. This represents 621 10^9 m^3, about 61 per cent of remaining established reserves.

Table 5.5 Pool reserves as of December 31, 2010 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
Commingled pools	4 110	14 358	2 739	2 118	621
Noncommingled pools		41 995	2 475	2 071	404
Total			**5 213**	**4 188**	**1 025**

In 2006, the ERCB issued orders establishing two development entities (DE No. 1 and 2)[2] that allow for commingling of gas without application of certain formations within these areas. Subsequently the ERCB amended the area described as DE 2 in August 2010. The commingling of gas of certain formations within these areas has enabled operators to produce reserves from zones that would otherwise have been uneconomic to produce on their own.

Table 5.6 shows that both DE No. 1 and 2 have remaining established reserves of 55 10^9 m^3 and 246 10^9 m^3, respectively. Gas reserves in commingled pools within DE No. 1 and 2 account for about 29 per cent of Alberta's remaining established reserves.

Table 5.6 Commingled pool reserves within development entities as of December 31, 2010 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
DE No. 1	673	1 861	372	317	55
DE No. 2	1 027	4 198	877	631	246
Total	**1 700**	**6 059**	**1 249**	**948**	**301**

5.1.3.4 Reserves of Conventional Natural Gas Containing Hydrogen Sulphide

H_2S is a naturally occurring substance present in many oil and gas reservoirs worldwide. Natural gas that contains more than 0.01 per cent H_2S is referred to as sour in this report.

In oil and gas reservoirs, H_2S is primarily generated through thermal and biological processes, both of which involve a reaction between dissolved sulfates and hydrocarbons. Thermally generated H_2S produces the highest concentrations of H_2S and occurs in reservoirs that have undergone diagenesis due to deep burial. Biologically generated H_2S is commonly found in shallower, lower temperature reservoirs but can also occur in sewers, swamps, composts, and manure piles.

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[2] A DE is a specific area consisting of multiple formations from which gas may be produced without segregation in the wellbore that is described in an order of the ERCB and subject to certain criteria in Section 3.051 of the *Oil and Gas Conservation Regulations.*

In Alberta, sour gas is found in several regions and formations across the province. **Figure R5.6** shows the wide distribution of sour gas wells across the province, with most occurring in central and western Alberta. The greatest concentrations of H_2S generally occur in the deeper Mississippian- and Devonian-

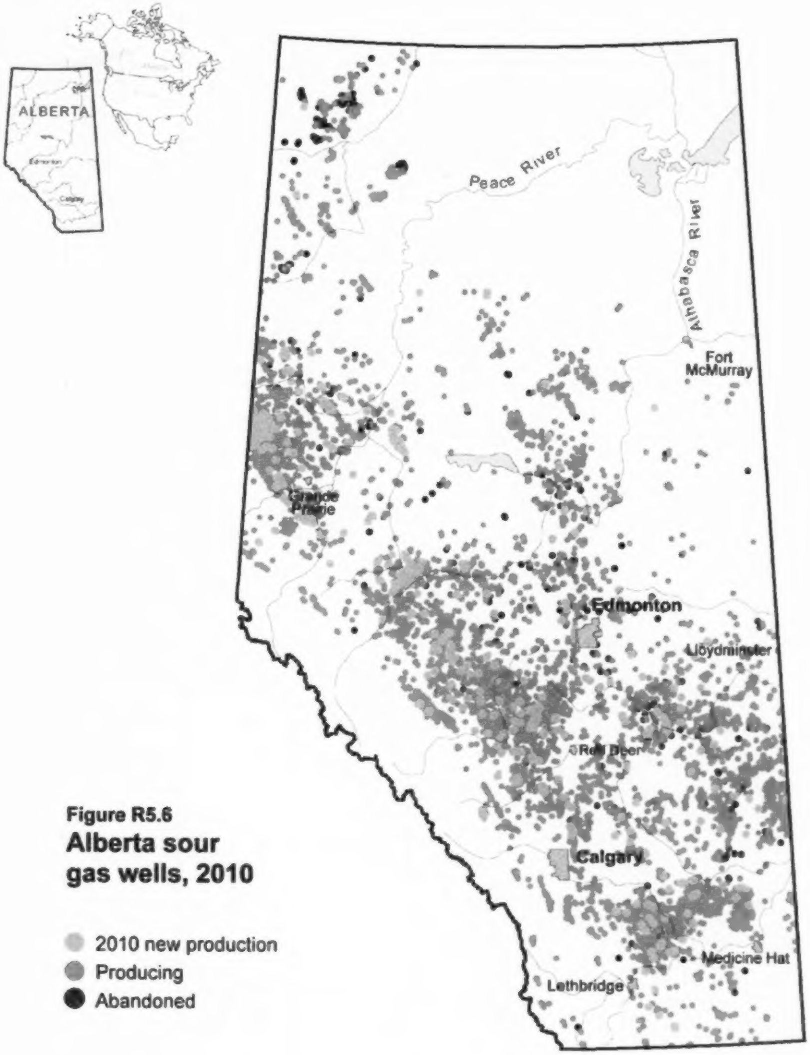

ALBERTA
Peace River
Athabasca River
Fort McMurray
Grande Prairie
Edmonton
Lloydminster
Red Deer
Calgary
Medicine Hat
Lethbridge
● 2010 new production
● Producing
● Abandoned

Figure R5.6
Alberta sour gas wells, 2010

aged carbonate rocks along the foothills and in west central Alberta. Lower concentrations of H_2S are more widely distributed across the province, primarily in the clastic rocks of Lower Cretaceous, Jurassic, and Triassic age, but also in Mississippian- and Devonian-aged carbonate rocks. Most new sour gas wells to come on production in 2010 are producing from the Lower Cretaceous and Jurassic in central and southern Alberta, just east of the foothills.

As of December 31, 2010, sour gas accounts for about 20 per cent (196 10^9 m^3) of the province's total remaining established reserves and about 21 per cent of raw natural gas production in 2010. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2010 is 8.4 per cent.

The distribution of reserves of sweet and sour gas provided in **Table 5.7** shows that 138 10^9 m^3, or about 70 per cent, of remaining sour gas reserves are in nonassociated pools. Since 2002, the proportion of remaining marketable reserves of sour to sweet gas has remained fairly consistent near 20 per cent of the total. The distribution of sour gas reserves by H_2S content, shown in **Table 5.8**, indicates that 33 10^9 m^3, or 17 per cent, of sour gas contains H_2S concentrations greater than 10 per cent, while 55 per cent (108 10^9 m^3) contains concentrations less than 2 per cent.

Table 5.7 Distribution of sweet and sour gas reserves, 2010

	Marketable gas (10^9 m^3)			Percentage	
Type of gas	**Initial established reserves**	**Cumulative production**	**Remaining established reserves**	**Initial established reserves**	**Remaining established reserves**
Sweet					
Associated and solution	753	597	156	14	15
Nonassociated	2 773	2 101	672	53	65
Subtotal	**3 526**	**2 698**	**829**	**67**	**80**
Sour					
Associated & solution	492	434	58	10	6
Nonassociated	1 195	1 057	138	23	14
Subtotal	**1 687**	**1 491**	**196**	**33**	**20**
Total	**5 213** **(185)[b]**	**4 188** **(149)[b]**	**1 025[a]** **(36.4)[b]**	**100**	**100**

[a] Reserves estimated at field plants.

[b] Imperial equivalent in Tcf at 14.65 pounds per square inch absolute and 60 F.

Table 5.8 Distribution of sour gas reserves by H_2S content, 2010

	Initial established reserves (10^9 m^3)		Remaining established reserves (10^9 m^3)			
H_2S content in raw gas (%)	**Associated and solution**	**Nonassociated**	**Associated and solution**	**Nonassociated**	**Total**	**%**
Less than 2	363	435	45	63	**108**	55
2.00-9.99	88	401	7	48	**55**	28
10.00-19.99	30	208	4	14	**18**	9
20.00-29.99	11	49	1	6	**7**	4
Over 30	0	102	0	8	**8**	4
Total	**492**	**1 195**	**57**	**139**	**196**	**100**
Percentage	29	71	29	71		

5.1.3.5 Reserves of Gas Cycling Pools

Gas cycling pools are gas pools rich in liquids into which dry gas is re-injected to maintain reservoir pressure and maximize liquid recovery. These pools contain 16.2 10^9 m^3 (1.6 per cent) of remaining gas reserves. The four largest pools are Harmattan East Commingled Pool 001, Valhalla MFP8524 Halfway, Waterton Rundle-Wabamun A, and Wembley MFP8524 Halfway, which together account for over 70 per cent of all remaining reserves of gas cycling pools. Surface loss and recovery factor are calculated on an energy basis in cycling pools. Reserves of major gas cycling pools are tabulated on both an energy content and a volumetric basis in **Appendix B**, **Table B.5**. The table also lists raw and marketable gas heating values used to convert from a volumetric to an energy basis. The detailed reservoir parameters of these pools are included in the Gas Reserves and Basic Data table, which is on the companion CD to this report (see **Appendix C**).

5.1.3.6 Reserves Methodology for Conventional Natural Gas

A detailed pool-by-pool list of reservoir parameters and reserves data for all conventional oil and gas pools is on CD (see **Appendix C**) and is available from ERCB Information Services.

The process of determining reserves takes into consideration geological, engineering, and economic factors. Though initial estimates contain a level of uncertainty, this level of uncertainty decreases over the life of the pool as more information becomes available and actual production is observed and analyzed. The initial reserves estimates are normally based on volumetric calculation, which uses bulk rock volume (based on isopach maps derived from geological interpretation of well log data) and initial reservoir parameters to estimate gas in place at reservoir conditions. Drainage areas for single-well pools range from 200 hectares (ha) for gas wells producing from regional sands with good permeability to 32 ha or less. The smaller areas are assigned to wells producing from low-permeability formations (less than 1 millidarcy) or from geological structures limited in areal extent.

Converting gas volume in place to specified standard conditions at the surface requires knowledge of reservoir pressure and temperature, and analysis of reservoir gas. A recovery factor is applied to the in-place volume to yield recoverable reserves, the volume that will actually be produced to the surface. Given their low viscosity and high mobility, gas recoveries typically range from 70 to 90 per cent. However, low-permeability gas reservoirs and reservoirs with underlying water may only recover 50 per cent or less of the in-place volume.

Once a pool has been on production for some time, material balance analysis involving the decline in pool pressure can be used as an alternative to volumetric estimation to determine in-place resources. Material balance is most accurate when applied to high-permeability, nonassociated, and noncommingled gas pools. Analysis of production decline data is a primary method for determining recoverable reserves, given that most of the larger pools in the province have been in decline for many years. When combined with an estimate of the in-place resource, it also provides a practical real-life estimate of the pool's recovery factor.

The procedures described above generate an estimate of initial established reserves of raw gas. The raw natural gas reserves must be converted to a marketable volume (i.e., the volume that meets pipeline specifications) by applying a surface loss or shrinkage factor. Based on the gas analysis for each pool, a surface loss is estimated using an algorithm that reflects expected recovery of liquids (ethane, propane, butanes, and pentanes plus) at field plants. Typically, 5 per cent is added to account for loss due to lease fuel (estimated at 4 per cent) and flaring. Surface losses range from 3 per cent for pools containing sweet dry gas to over 30 per cent for pools with raw gas that contains high concentrations of H_2S and gas liquids. Therefore, marketable gas reserves of individual pools on the ERCB's gas reserves database reflect expected marketable reserves after processing at field plants. The pool reserves numbers published by the ERCB represent estimates for in-place resources, recoverable reserves, and associated recovery factors based on the most reasonable interpretation of available information from volumetric estimates, production decline analysis, and material balance analysis.

Additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. Exceptions to this are the gas shipped to Chicago on the Alliance Pipeline and some of the dry southeastern Alberta gas. As removal of these liquids cannot be traced back to individual pools, a gross adjustment for the liquids is made to arrive at the estimate for remaining reserves of marketable gas in the province. These reserves therefore represent the volume and average heat content of gas after removal of liquids from both field and straddle plants.

It is expected that about 30.2 10^9 m^3 of liquid-rich gas will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas (estimated at the field plant gate) from 1025.1 10^9 m^3 to 994.9 10^9 m^3 and the thermal energy content from 39.9 to 37.1 exajoules (10^9 joules).

Figure R5.7 also shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example, of the total ethane content in raw natural gas, about 25 per cent is expected to be removed at field plants and an additional 40 per cent at straddle plants. Therefore, the ERCB estimates reserves of liquid ethane that will be extracted based on 65 per cent of the total raw ethane gas reserves. The remaining 35 per cent of the ethane is left in the marketable gas and sold for its heating value. This ethane represents a potential source for future ethane supply.

Reserves of NGLs are discussed in more detail in Section 6.

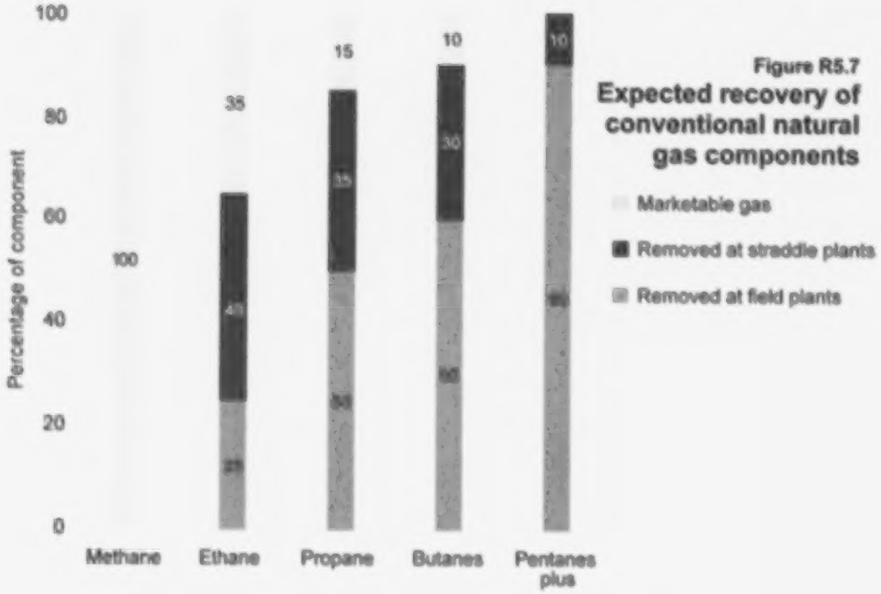


Figure R5.7
Expected recovery of conventional natural gas components

5.1.3.7 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in **Appendix B, Table B.6**. Each multifield pool shows the individual remaining established reserves assigned to each field and the total remaining established reserves for the multifield pool.

5.1.4 Established Reserves of CBM

CBM is the methane gas found in coal, both as adsorbed gas and as free gas. Unlike conventional gas, which occurs as discrete accumulations, or pools, CBM most often occurs in interconnected coal seams within defined stratigraphic zones as laterally continuous accumulations or deposits.

CBM may contain small amounts of carbon dioxide and nitrogen (usually less than 5 per cent). H_2S is not normally associated with CBM production, as the coal adsorption coefficient for H_2S is far greater than for methane. The heating value of CBM is generally about 37 megajoules per cubic metre.

5.1.4.1 CBM Potential by Geologic Strata

Based on thousands of coal holes and oil and gas wells, coal is known to underlie most of central and southern Alberta, one of the largest geographical extents of continuous coal in North America. Coal seams occur as layers or beds within several Cretaceous coal zones. While individual coal seams can be laterally discontinuous, coal zones can be correlated very well over regional distances. All coal seams contain CBM to some extent and each seam is potentially capable of producing some CBM.

The ERCB recognizes CBM reserves in the following horizons in Alberta:

- **Coals of the Horseshoe Canyon Formation and Belly River Group**—Horseshoe Canyon coals generally have low gas content and low water volume, with production referred to as "dry CBM." The first commercial production of CBM in Alberta was from these coals, and they constitute the majority of CBM reserves booked. Reserves from the Taber or MacKay coal zones of the Belly River Group have not yet been established.
- **Coals of the Mannville Group**—Mannville coals generally have high gas content and high volume of saline water, requiring extensive pumping and water disposal. The initial reserves for areas other than the Corbett area within the Mannville Group have been set at cumulative production.

The Ardley coals of the Scollard Formation and the Kootenay coals of the Mist Mountain Formation also show potential for production, but at this time no CBM reserves have been calculated for these coals.

An individual CBM zone is defined as all coal seams within a formation separated by less than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool. Several individual producing coal seams in one CBM zone are considered to be one CBM pool for regulatory and administrative purposes. For administrative purposes, previous pools limited by field boundaries have been converted to multifield CBM pools. However, as multifield pools are still problematic in grouping CBM resource and reserves estimates, the ERCB now groups CBM volumes into deposit-based play areas.

5.1.4.2 CBM Deposits, Play Areas, and Play Subareas

Although CBM is regulated and administered as if it existed in pools, CBM accumulations exist more as deposits. The ERCB assesses CBM deposits for reserve determination in a manner similar to the way it assesses oil sands deposits. CBM deposits are stratigraphic intervals that extend over a large geographic area and may include one or more CBM zones. Unlike oil sands deposits, however, the ERCB has yet to formally define CBM deposits (e.g., through Board orders) because it is still monitoring development activities. Currently, CBM deposits are informally based on formations, with the two main CBM deposits being the Horseshoe Canyon and the Mannville. Within each of these deposits, development activities have until now been concentrated mainly in a single smaller play area.

While Mannville activity is clustered almost exclusively in the Corbett area, the more widespread Horseshoe Canyon play occurs over a large area between Calgary and Edmonton. Currently, the Horseshoe Canyon play area is within the ERCB-designated DE No. 1 and the Southeastern Alberta Gas System. The current play areas for the Horseshoe Canyon and Mannville deposits are shown in **Figure R5.8**.

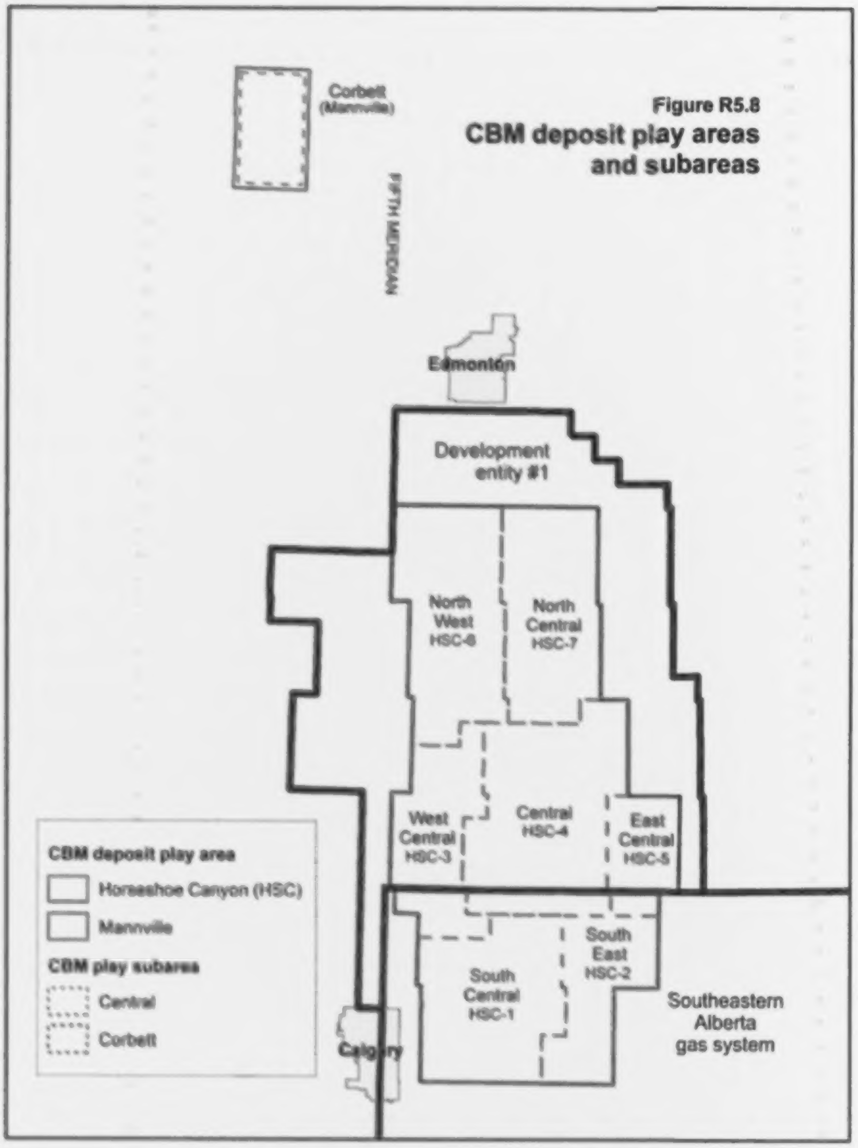


Figure R5.8
CBM deposit play areas and subareas

Corbett (Mannville)
FIFTH MERIDIAN
Edmonton
Development entity #1
North West HSC-6
North Central HSC-7
West Central HSC-3
Central HSC-4
East Central HSC-5
South East HSC-2
South Central HSC-1
Southeastern Alberta gas system
Calgary
CBM deposit play area
Horseshoe Canyon (HSC)
Mannville
CBM play subarea
Central
Corbett

Although coal zones are regionally extensive, the values of reservoir parameters used for reserves estimates are determined locally. As a result, for reserves estimation and reporting purposes, the large central Alberta play area of the Horseshoe Canyon deposit is divided into subareas based on reservoir and production profile differences defined by control well data within the deposit. The location of the Horseshoe Canyon play subareas is also shown on **Figure R5.8**.

5.1.4.3 CBM Reserves Determination Method

The ERCB uses three-dimensional block models to estimate in-place CBM resources for each play area or subarea. Desorption data are used on a zonal basis by applying gas content trends from core to all coals in each zone to estimate in-place CBM resources. Desorption values from drill cuttings are used to validate the continuity of the zonal trends from core.

Current reserves estimates are determined by applying an average recovery factor based on analysis of control well data for each play subarea. These recovery factors are shown for each subarea in **Table 5.9**. The method of determining reserves depends on flowmeter values and changes in reservoir pressure as determined by qualitatively comparing annual measurements in each CBM zone. If the data or production reporting is missing, then the result is assumed to be zero, which becomes the recovery factor. Future analysis is expected to improve estimates of recovery factors. CBM data are available on two systems from the ERCB: summarized net pay data on the Integrated Geological database and individual coal seam thickness picks on the Coal Hole database.

5.1.4.4 Detail of CBM Reserves and Well Performance

Horseshoe Canyon coals, which are mainly gas-charged with little or no pumping of water required, remain the main focus of industry and currently have the highest established reserves (see **Table 5.9**). New data have supported the inclusion of additional areas within many of the Horseshoe Canyon CBM play subareas. As a result of the latest analysis of flowmeter and pressure data, all subareas have had a notable increase in recovery factor. A correction was made to the weighted average of the coal thickness in 2010. In subarea 1, where coals are deeper and have higher gas content, an increase in both initial gas in place and recovery factor from more comprehensive coverage of control well data has resulted in this area having the largest initial established reserves of CBM in the Horseshoe Canyon play.

The ERCB has decreased its estimate of initial gas in place for the Corbett play area of the Mannville CBM deposit. This is based on the latest analysis of flowmeter and pressure data and the production profiles of new multilateral horizontal wells. Ongoing Mannville CBM production in adjacent areas should have increased gas flow because of progressive dewatering of the deposit outside the current play area, which still requires proper disposal of saline water.

The undefined portion of **Table 5.9** includes noncommercial production from these areas, but reserves have not been booked pending commercial production.

Table 5.9 CBM gas in place and reserves by deposit play area, 2010

Deposit and play subareas	Average net coal thickness (m)	Coal reservoir volume (10^9 m^3)	Estimated gas content (m^3 gas/m^3 coal)	Initial gas in place (10^9 m^3)	Average recovery factor (%)	Initial established reserves (10^9 m^3)	Cumulative production (10^9 m^3)	Remaining established reserves (10^9 m^3)
Horseshoe Canyon[a]								
1	10.1	35.37	2.95	104.38	27	28.56	5.05	23.51
2	4.3	9.04	1.06	9.61	25	2.37	0.37	2.00
3	5.8	13.91	2.41	33.56	30	10.19	3.18	7.01
4	6.4	28.39	1.72	48.84	34	16.47	9.41	7.06
5	3.0	3.93	1.11	4.37	26	1.13	0.58	0.55
6	3.5	8.67	1.57	13.58	30	4.14	2.58	1.56
7	4.4	14.74	1.30	19.19	32	8.31	5.89	2.42
Undefined[b]	-	-	-	-	-	0.58	0.58	0.00
Subtotal	**5.4[c]**	**114.06**	**2.05[c]**	**233.53**	**31[c]**	**71.74**	**27.64**	**44.10**
Mannville								
Corbett	4.9	6.97	9.73	67.86	42	28.18	4.67	23.51
Undefined[b]	-	-	-	-	-	0.59	0.59	0.00
Total		**121.03**		**301.39**	**33[c]**	**100.5**	**32.90**	**67.60**

[a] Includes Upper Belly River CBM.

[b] Most of the undefined areas are for tests in the Mannville coals, but include a few Horseshoe Canyon, Ardley, and Kootenay wells with minor production and many Belly River recent recompletions with incomplete reporting.

[c] Weighted average.

5.1.4.5 Commingling of CBM with Conventional Gas

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined by the ERCB until 1995. Significant development with commercial production commenced in 2002. The actual CBM production to date continues to be uncertain because of the difficulty differentiating CBM from conventional gas production where commingled production occurs.

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. For CBM, this includes commingling of two or more CBM zones, as well as the commingling of one or more CBM zones with one or more conventional gas pools.

As the Horseshoe Canyon and Belly River formations generally contain "dry CBM" with little or no pumping of water required, the commingling of CBM and other conventional gas pools is common. Because many of the sandstone gas reservoirs in these strata may be marginally economic or uneconomic if produced separately, commingling with CBM can be beneficial from a resource conservation perspective. In some circumstances, commingling can have the additional benefit of minimizing surface impact by reducing the number of wells needed to extract the same resource.

CBM hybrid wells lack segregated reservoir data from commingled zones, making reserve estimation more difficult. Many hybrid wells report only CBM production, even though analysis of the well indicates that there is unsegregated production of both CBM and conventional gas. Recompleted wells with new CBM production may not report to a separate production occurrence. To address these data constraints, the following was completed on wells with commingled production:

- Wells with completions that were determined to be only in coal were assigned as CBM-only production.
- The CBM production contribution from hybrid wells was interpolated from more than 1800 CBM control wells and other wells with confirmed CBM-only production. The volume of CBM production was then subtracted from the total volume to give the conventional gas production.
- CBM production from conventional wells recompleted for CBM and not reported separately was included. There is an administrative process in place to correct for the CBM production in these cases.

5.1.5 Shale Gas Resources

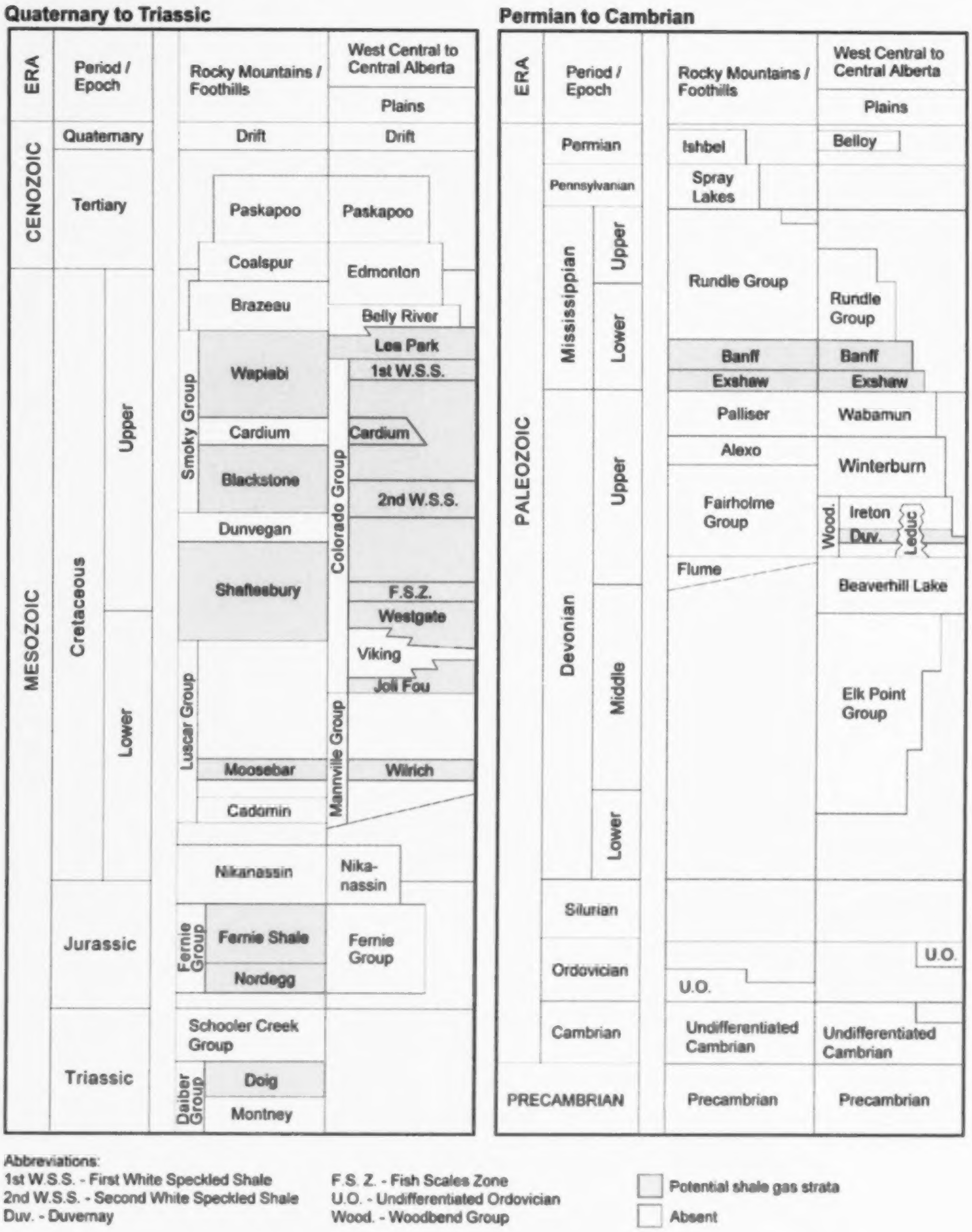
Shales are the traditional source rocks for conventional hydrocarbon accumulations as well as a seal for conventional reservoirs. More recently, shales have become a target for production of unconventional gas, condensate, and oil. Shale gas refers to natural gas that is found in shale and other related rock types, existing mostly as free gas in the matrix and fractures and as adsorbed gas on organic matter and clays. Typically, these fine-grained rocks have extremely low matrix permeability and stimulation is required to produce fluids from the rock. Shale gas is not restricted to shale, since claystones, mudstones, siltstones, fine-grained sandstones, and carbonates can also be found within potential gas shale strata. Furthermore, not all shale has the potential to contain economic quantities of shale gas.

Based on an evaluation of geophysical logs from oil and gas wells, shale is known to underlie most of the province, existing in various formations both shallow and deep. Not all shale, however, is organic-rich, and for the time being industry is concentrating exploration on relatively organic-rich shale rather than on shale lacking in organic matter.

More than 15 shale formations exhibit potential for shale gas. Gas shales also include those rocks that contain a relatively small amount of organic matter but are not regarded as traditional source rocks for oil and gas, such as much of the Colorado Group shale. The generalized stratigraphic chart of formations shown in **Figure R5.9** details the formations (indicated with red shading) that have organic matter that could have potential to produce gas. Not all of these formations are source rocks; some contain small amounts of organic matter and may be more akin to low-permeability strata than to organic-rich shale.

Figure R5.9

Potential shale gas strata.


Quaternary to Triassic
ERA
Period / Epoch
Rocky Mountains / Foothills
West Central to Central Alberta
Plains
CENOZOIC
Quaternary
Drift
Drift
Tertiary
Paskapoo
Paskapoo
Coalspur
Edmonton
Brazeau
Belly River
MESOZOIC
Cretaceous
Upper
Smoky Group
Lea Park
Wapiabi
1st W.S.S.
Cardium
Cardium
Blackstone
Colorado Group
2nd W.S.S.
Dunvegan
Shaftesbury
F.S.Z.
Westgate
Lower
Luscar Group
Viking
Joli Fou
Mannville Group
Moosebar
Wilrich
Cadomin
Nikanassin
Nika-nassin
Jurassic
Fernie Group
Fernie Shale
Nordegg
Fernie Group
Triassic
Schooler Creek Group
Daiber Group
Doig
Montney
Permian to Cambrian
ERA
Period / Epoch
Rocky Mountains / Foothills
West Central to Central Alberta
Plains
PALEOZOIC
Permian
Ishbel
Belloy
Pennsylvanian
Spray Lakes
Mississippian
Upper
Lower
Rundle Group
Rundle Group
Banff
Banff
Exshaw
Exshaw
Devonian
Upper
Palliser
Wabamun
Alexo
Winterburn
Fairholme Group
Wood.
Ireton
Duv.
Leduc
Flume
Beaverhill Lake
Middle
Elk Point Group
Lower
Silurian
Ordovician
U.O.
U.O.
Cambrian
Undifferentiated Cambrian
Undifferentiated Cambrian
PRECAMBRIAN
Precambrian
Precambrian
▨ Potential shale gas strata
☐ Absent

Abbreviations:
1st W.S.S. - First White Speckled Shale
2nd W.S.S. - Second White Speckled Shale
Duv. - Duvernay
F.S.Z. - Fish Scales Zone
U.O. - Undifferentiated Ordovician
Wood. - Woodbend Group

The presence of organic-rich or relatively organic-rich shale throughout the province does not mean that there will be pools of shale gas or wells drilled throughout all parts of the province. Shale is still a seal for conventional and nonconventional hydrocarbon reservoirs and much of the shale encountered will not yield economic quantities of gas.

The geographic distribution of major potential shale gas horizons is shown in **Figure R5.10** and includes shales of the Colorado Group and equivalents, the Fernie Group, Banff and Exshaw formations, and the Woodbend Group and Muskwa Formation.

The specific areas in which exploration is taking place in Alberta in some of the formations mentioned above can be viewed in **Figure R5.11**. The depth from the surface to the shale formation increases westward in Alberta. Typically, the deeper formations have a higher formation pressure, which is a favourable aspect for shale gas exploration.

Development activities to date for shale gas production have mainly been concentrated in east-central Alberta within the Colorado Group shales. Colorado shale gas is clustered around the Wildmere area (**Figure R5.10**), where a number of shale gas zones are being commingled. Shale gas activity in this area is based mainly on vertical drilling technology and recompletions of existing wells; however, a few horizontal wells have been drilled for shallow shale gas over the past year. In southeast Alberta (see **Figure R5.10**), where shallow gas has been considered conventional gas for all of its production history, the ERCB will not reclassify any gas production as shale gas because this would be administratively unwieldy. In all other areas, drilling is predominantly of horizontal wells. Note that there may be other wells in the province that have perforated shales; however, as there is currently no separate status or classification for a shale well, these wells are often difficult to locate in databases. The ERCB will continue to monitor shale gas activity in the province.

While the ERCB expects to publish in-place resource estimates soon, the estimate of established reserves will likely be delayed until sufficient data are available to conduct a reasonable assessment of shale gas recoverability. The ERCB will monitor the anticipated increased shale gas exploration and development activity for such data. As additional data become available from more areas, the ERCB expects that play areas (areas of significant industry activity) of the different deposits will be identified. These play areas may be subdivided based on differences in reservoir parameters and production profiles.

5.1.5.1 Gas Potential in Mixed Lithology Strata of the Montney Formation

Conventional production has occurred from the upper Montney Formation for many decades. Recently, fine-grained sandstones that are lower in the stratigraphic column have been targets for gas and oil in Alberta and B.C. These sandstones are of low permeability and in Alberta are more akin to tight gas than to shale gas deposits.

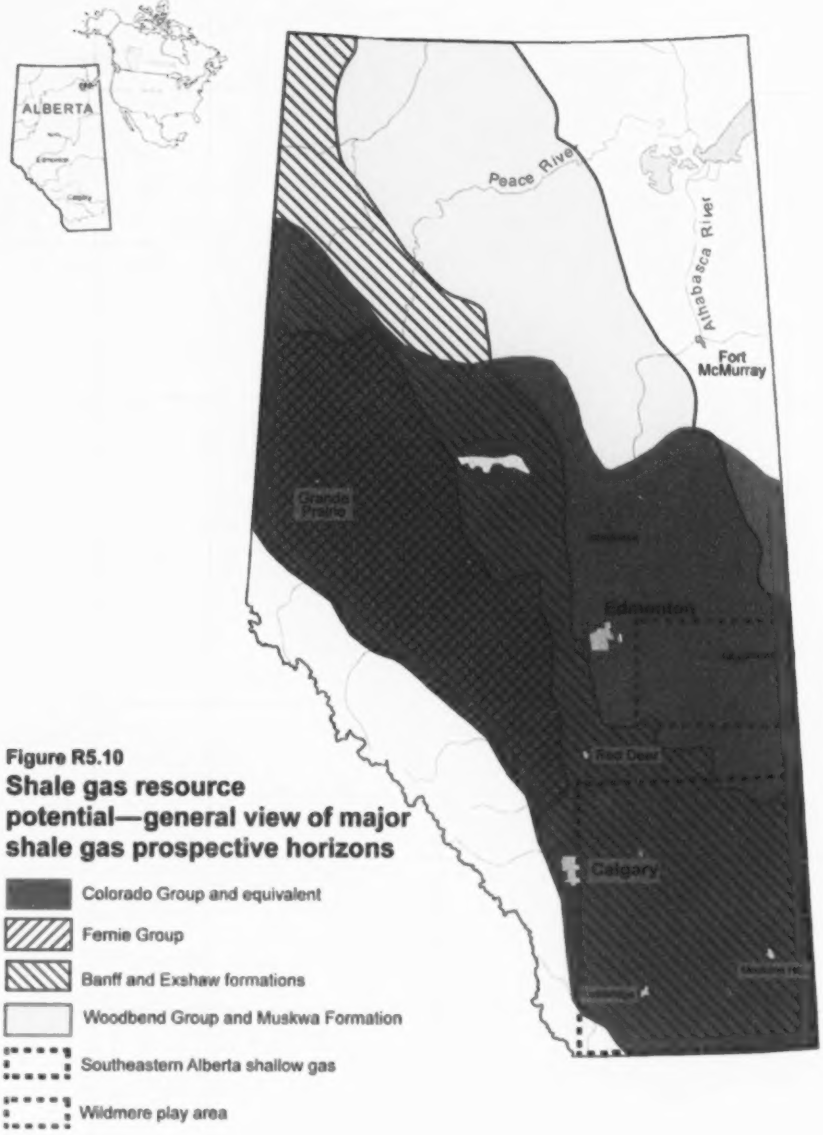

ALBERTA
Peace River
Athabasca River
Fort McMurray
Grande Prairie
Edmonton
Red Deer
Calgary
Colorado Group and equivalent
Fernie Group
Banff and Exshaw formations
Woodbend Group and Muskwa Formation
Southeastern Alberta shallow gas
Wildmere play area

Figure R5.10
Shale gas resource potential—general view of major shale gas prospective horizons

The Montney Formation in Alberta subcrops along its eastern edge and increases to more than 200 m thick in western Alberta. Most of the interval comprises dolomitic siltstones with the aforementioned sandstones interbedded with the siltstone. The organic content throughout the Montney Formation in Alberta is low (1 to 2 weight per cent). The interbedded sandstones are currently the primary target; however, the future holds promise for the dolomitic siltstones. As the formation is of mixed lithology

and is classified as conventional production, potential reclassification as shale gas will be determined in the future on a case-by-case basis.

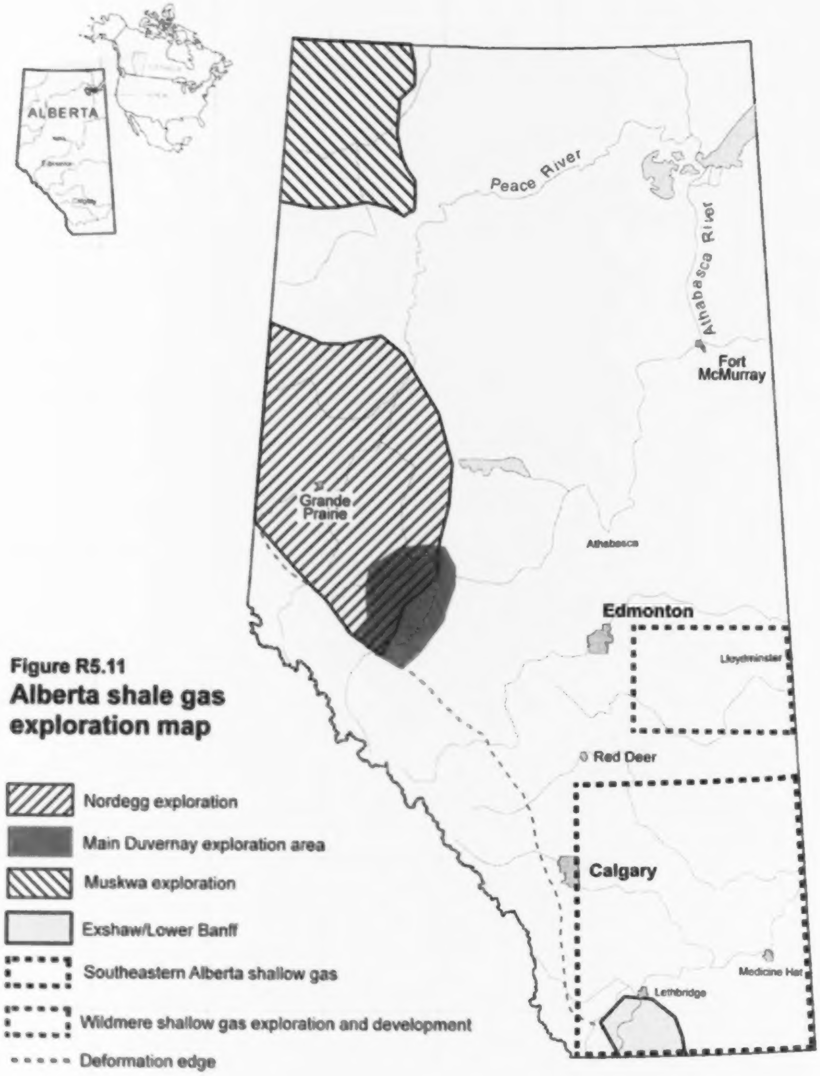
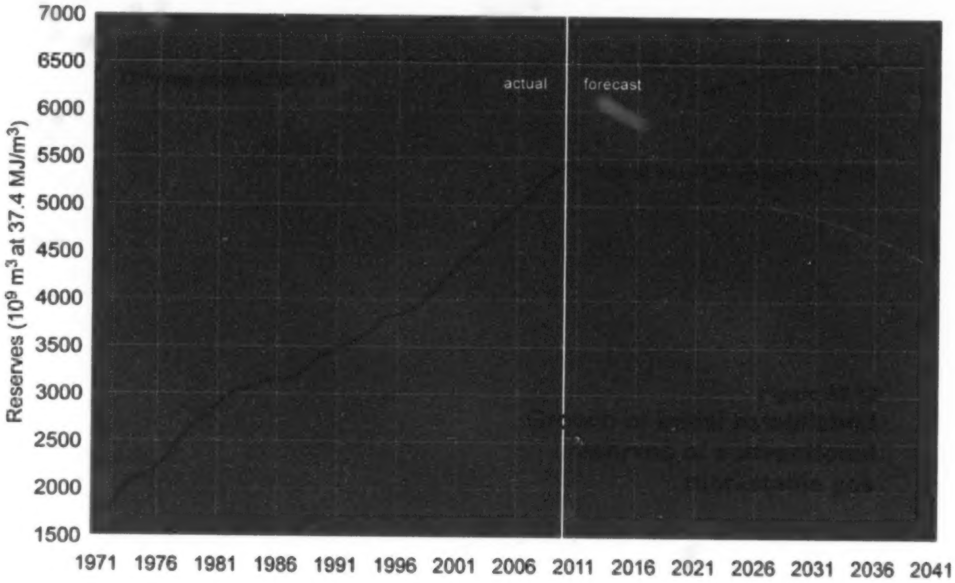

ALBERTA
Peace River
Athabasca River
Fort McMurray
Grande Prairie
Athabasca
Edmonton
Lloydminster
Red Deer
Calgary
Medicine Hat
Lethbridge
▨ Nordegg exploration
■ Main Duvernay exploration area
▧ Muskwa exploration
□ Exshaw/Lower Banff
Southeastern Alberta shallow gas
Wildmere shallow gas exploration and development
Deformation edge

Figure R5.11
Alberta shale gas exploration map

5.1.6 Ultimate Potential of Conventional Natural Gas

The EUB and the National Energy Board (NEB) jointly released *Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas* (EUB/NEB 2005 Report), an updated estimate of the ultimate potential for conventional natural gas. The ERCB has adopted the medium case representing an ultimate potential of 6276 10^9 m^3 "as is" volume (223 trillion cubic feet [Tcf]) or 6528 10^9 m^3 (232 Tcf) at the equivalent standard heating value of 37.4 MJ/m^3. This estimate does not include unconventional gas, such as CBM. **Figure R5.12** shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth up to 2010 equalled 5420 10^9 m^3. **Figure R5.13** plots production and remaining established reserves of marketable gas compared with the estimate of ultimate potential.

Table 5.10 provides details about the ultimate potential of marketable gas, with all values shown both "as is" and converted to the equivalent standard heating value of 37.4 MJ/m^3. It shows that initial established marketable reserves of 5214 10^9 m^3, or 83 per cent of the ultimate potential of 6276 10^9 m^3 ("as is" volumes), have been discovered as of year-end 2010. This leaves 1062 10^9 m^3, or 17 per cent, as yet-to-be-discovered reserves. Cumulative production of 4188 10^9 m^3 at year-end 2010 represents 67 per cent of the ultimate potential, leaving 2088 10^9 m^3, or 33 per cent, available for future use.



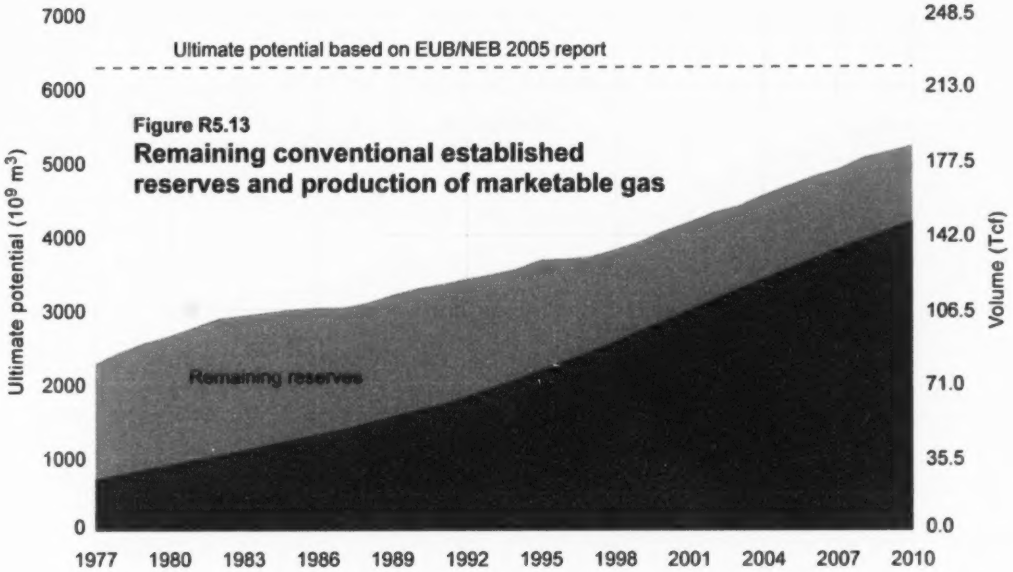


Figure R5.13
Remaining conventional established reserves and production of marketable gas

Table 5.10 Remaining ultimate potential of marketable conventional gas, 2010 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m^3)	at 37.4 MJ/m^3
Ultimate potential	6 276	6 528
Minus initial established reserves	-5 214	-5 420
Yet-to-be-established reserves	**1 062**	**1 108**
Initial established reserves	5 214	5 420
Minus cumulative production	-4 188	-4 354
Remaining established reserves	**1 025**	**1 066**
Yet-to-be-established reserves	1 062	1 108
Plus remaining established reserves	+1 025	+1 066
Remaining ultimate potential	**2 088**	**2 174**

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure R5.14**. It shows that the Western Plains (Area 2) contains 36 per cent of the remaining established reserves and 18 per cent of the yet-to-be-established reserves. Although most gas wells are being drilled in the Southern Plains (Areas 3, 4, and 5), **Figure R5.14** shows that, based on the EUB/NEB 2005 Report, Alberta conventional natural gas supplies will continue to depend on significant new discoveries in the Western Plains.

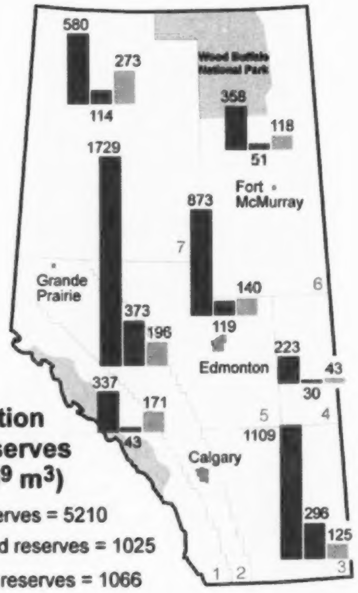

580
273
114
Wood Buffalo National Park
358
118
51
1729
Fort McMurray
873
7
Grande Prairie
140
6
373
196
119
223
Edmonton
43
30
337
171
5
4
43
1109
Calgary
296
125
1
2
3

Figure R5.14

Regional distribution of Alberta gas reserves by PSAC area (10^9 m^3)

- Initial established reserves = 5210
- Remaining established reserves = 1025
- Yet-to-be-established reserves = 1066

Figure R5.15 shows by geological period the discovered and ultimate potential gas in place for year-end 2005. It illustrates that 57 per cent of the ultimate potential gas in place is in the Upper and Lower Cretaceous. Discovered gas in place represents the known value as of December 2010. Current methods of evaluating gas in place have changed from discrete pooling of wells in 2005 to more of a block-type model in areas such as the development entities and Southeastern Alberta.

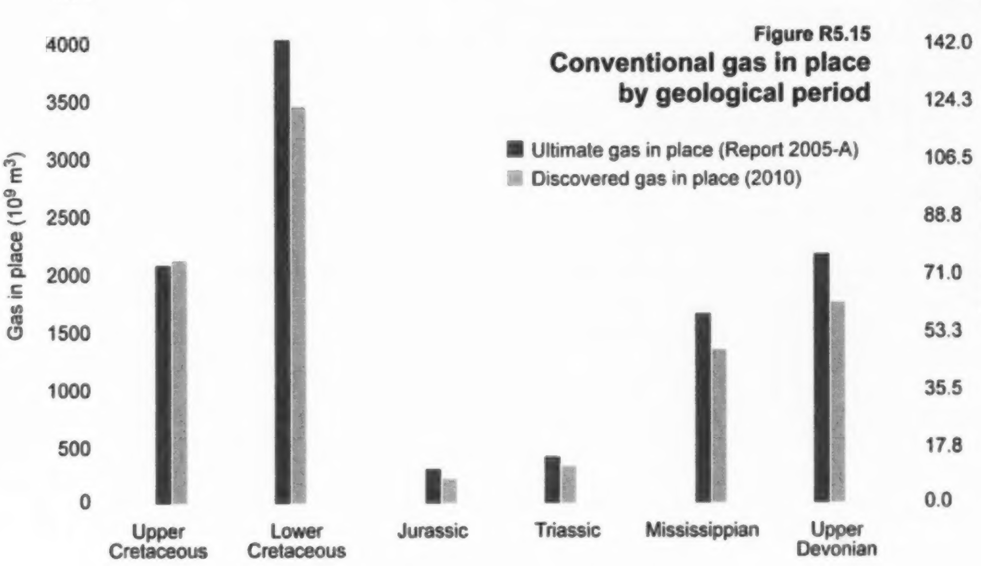


Figure R5.15

Conventional gas in place by geological period

5.1.7 Ultimate CBM Gas in Place

The Alberta Geological Survey (AGS), in *Earth Sciences Bulletin 2003-03*, estimated that there are 14 trillion (10^{12}) m^3 (500 Tcf) of gas in place within all of the coal in Alberta. This estimate is accepted as the initial determination of Alberta's ultimate CBM gas in place (see **Table 5.11**). However, due to the early stage of CBM development and the resulting uncertainty of recovery factors, the recoverable portion of these large values—the ultimate potential—has yet to be determined.

Table 5.11 Ultimate CBM gas in place[a]

Area	10^{12} m^3	Tcf[b]
Upper Cretaceous/Tertiary—Plains	4.16	147
Mannville coals—Plains	9.06	320
Foothills/Mountains	0.88	31
Total	**14.10**	**500**

[a] EUB/AGS *Earth Sciences Report 2003-03: Production Potential of Coalbed Methane Resources in Alberta*

[b] Tcf—trillion cubic feet

Although not a type of natural gas, there is potential in Alberta for the production of synthetic gas from coal and other sources. Synthetic gas from coal is discussed in Section 8.

5.2 Natural Gas Supply and Demand

In projecting marketable natural gas production, the ERCB considers three components: expected production from existing connections, expected production from new connections, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be established reserves of natural gas in the province. The ERCB projects conventional gas production from oil wells and gas connections separately from CBM connections. The forecasts are combined and referred to as total gas production in Alberta.

The ERCB annually reviews the projected demand for Alberta natural gas. The focus of these reviews is on intra-Alberta natural gas use, and a detailed analysis is undertaken of many factors, such as population growth, industrial activity, alternative energy sources, and other factors that influence gas consumption in the province.

5.2.1 Marketable Natural Gas Production—2010

With weak drilling activity for natural gas the second year in a row, Alberta's production continued to slide, although the drop was less severe than in 2009. In 2010, total marketable natural gas production in Alberta, including unconventional production, declined by 5.6 per cent to 318.7 10^6 m^3/d from 337.7 10^6 m^3/d. The decline in production is less than the 7.9 per cent decrease in 2009 from 2008 volumes. In 2010, natural gas from conventional gas and oil connections, at 294.0 10^6 m^3/d (standardized to 37.4

MJ/m^3), represented 92.3 per cent of production. The remaining 7.7 per cent of gas supply came from CBM and shale gas connections at 24.4 10^6 m^3/d and 0.3 10^6 m^3/d, respectively.

Total gas production from identified CBM and CBM hybrid connections decreased 3.6 per cent in 2010 to 24.4 10^6 m^3/d from the revised 2009 volume of 25.3 10^6 m^3/d. Gas production from connections completed in the Horseshoe Canyon Formation was 21.1 10^6 m^3/d, representing 87 per cent of total CBM production. Gas production from the Mannville Formation was 3.3 10^6 m^3/d. These volumes include production from connections outside the defined CBM subareas as outlined later in this section.

Marketable natural gas production volumes for conventional gas are calculated based on production data from the "Supply and Disposition of Marketable Gas" in *ST3: Alberta Energy Resource Industries Monthly Statistics*, as shown in **Table 5.12.** Gas production from CBM and shale gas connections is determined separately.

Table 5.12 Conventional marketable natural gas volumes (10^6 m^3)

Conventional marketable gas production	2010
Total raw gas production including storage withdrawals	139 419.6
Minus production from CBM and hybrid connections	-8 893.3
Minus production from shale gas connections	-95.0
Total conventional raw gas production	130 431.3
Minus storage withdrawals	-6 064.4
Net raw gas production	124 366.9
Minus total injection	-7 901.9
Net raw gas production	116 465.0
Minus processing shrinkage–raw	-7 455.4
Minus flared—raw	-533.1
Minus vented—raw	-364.7
Minus fuel—raw	-10 725.1
Plus storage injections	5 787.3
Conventional marketable gas production at "as-is" conditions	103 174.0
Conventional marketable gas production at 37.4 MJ/m^3	107 301.0
Daily rate of conventional marketable gas at 37.4 MJ/m^3	(294.0 10^6 m^3/d)

Major factors affecting Alberta natural gas production are basin maturity, drilling and connection activity, the location of Alberta's reserves, well production characteristics, gas liquids content, market demand, and natural gas prices and their volatility.

Three continuous themes were instrumental in shaping Alberta's natural gas industry and activity levels over the past year. First, North American gas production has been escalating as a result of low-cost shale gas production. New multistage completion technology is being used to fracture rock at intervals along a horizontal well to release gas trapped in shale gas deposits. There is concern that drilling activity continues to be too high for gas demand to absorb, resulting in surplus gas supply. In 2010, natural gas prices in Alberta averaged $3.57 dollars per gigajoule (GJ), down 2 per cent from the 2009 average natural gas price of $3.65/GJ. Alberta's relatively high drilling and development costs led to reduced investment in Alberta's conventional gas development, which resulted in a year-over-year reduction in both gas drilling activity and production.

In 2010, U.S. shale gas production reached 375.8 10^6 m^3/d (4.87 Tcf), representing 23 per cent of total U.S. natural gas production.[3] This represents 15 per cent more sales gas than was produced in Alberta last year. Shale gas production in the U.S. has grown rapidly. In 2000, shale gas production in the U.S. was only 30.1 10^6 m^3/d (0.39 Tcf).

The second factor shaping Alberta's natural gas industry in 2010 was the slowing of the decline in natural gas production. To combat the low price of natural gas, producers in Alberta are drilling more horizontal gas wells, instead of vertical wells, and using multistage completion technology, which substantially improves well productivity when used in combination with horizontal wells.

The third factor playing into the energy sector in Alberta is the competition for investment dollars in the crude oil industry. The resurgence in crude oil drilling activity is a result of high crude oil prices and the application of multistage fracturing technology in horizontal wells. In 2010, 41 per cent of new wells placed on production were for crude oil. Roughly 50 per cent of these wells are horizontal, many of them using multistage fracturing technology to access the tight oil formations of central Alberta. Technology used earlier in the Bakken oil Formation of North Dakota and southeastern Saskatchewan is now successfully being used in Alberta. Just four years ago only 11 per cent of the 17 399 wells placed on production in the province were crude oil wells.

Also, gas producers in Alberta and elsewhere are searching to develop liquids rich gas plays as a way to offset the extremely low natural gas prices. These gas liquids—propane, butanes, and pentanes plus—are by-products of natural gas and priced relative to crude oil. Historically, the "rule of thumb" was that crude oil and natural gas prices generally maintained a 6:1 ratio,[4] which is close to thermal parity. Now the relationship is 25:1, an indication that natural gas is very inexpensive compared with liquid forms of energy. Natural gas producers with a steady stream of liquid output can therefore continue to drill new wells despite the low gas price outlook because the higher valued liquids improve the economics of natural gas drilling.

While Alberta gas production declined in 2010 from 2009 levels, gas production in British Columbia (B.C.) increased and is responsible for growth of the TransCanada PipeLines Limited (TCPL) Alberta natural gas pipeline system. In December 2010, TCPL's Groundbirch pipeline came on stream to transport new shale gas from the Montney play in northeast B.C. to the Alberta border where it connects with TCPL's Alberta System. The gas is destined for markets in Canada and the U.S. TCPL's second pipeline project—to bring shale gas from the Horn River region of B.C. on stream—received approval in

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[3] Energy Information Administration (EIA).

[4] One barrel of crude oil priced at roughly six times the price of one million British thermal units (MMbtus) of natural gas.

December 2010. The Horn River Pipeline project in northeast B.C. will transport natural gas from the Fort Nelson region to the Alberta border. The gas will connect to TCPL's Alberta System before heading to markets. TCPL expects the Horn River region to account for 140.8 $10^6 m^3/d$ (5 billion cubic feet per day [bcf/d]) by the end of the decade.

These new supply projects require expansions to TCPL's Alberta System, and according to TCPL, the five-year outlook for spending on the expansion of TCPL's Alberta System as a result of capital investments in facilities is over $2 billion. TCPL reports that it anticipates an increase in gas throughput in the Alberta System as a result of these new projects, even with the projected decline in Alberta-sourced natural gas volumes, to the benefit of all ratepayers. If the gas moves through Alberta straddle plants, the value of natural gas liquids remaining in the gas stream can also be captured.

5.2.2 Natural Gas Connections—2010

Gas well connections include newly drilled wells placed on production and recompletions into new zones of existing wells. This section identifies recompletions as those connections that went on production at least one year after the finished drilling date.

5.2.2.1 Conventional Natural Gas Connections

The number of gas well connections in 2010 has not been this low since 1995. **Figure S5.1** shows the number of new conventional gas connections in Alberta in the last two years by geographical delineation set by PSAC. In 2010, 3099 new conventional gas connections were placed on production in the province, a decrease of 19 per cent from 2009. This is the fourth straight year of reductions in conventional gas connections.

New conventional gas connection activity for 2010 and 2009 is shown in **Table 5.13**. The table provides information on the number of gas connections in vertical or directional wells versus horizontal wells drilled in each PSAC geographical area. The table also breaks down the number of new gas connections placed on production versus connections recompleted in existing wellbores and placed on production. In 2010, roughly 25 per cent of gas connections were recompletions into existing wellbores.

The number of horizontal gas wells drilled and connected in the province is increasing as a percentage of the total. In 2010, about 18 per cent of new gas connections were horizontal wells compared with 7 per cent in 2009.

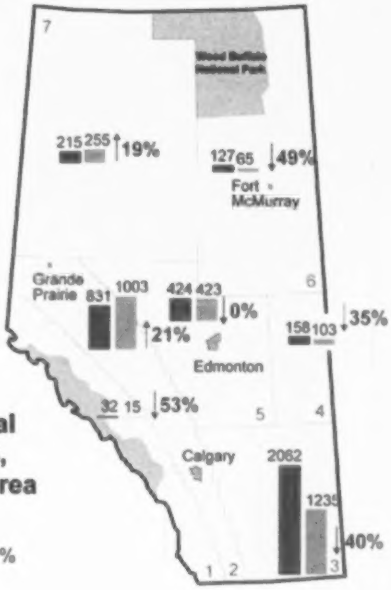
7
Wood Buffalo National Park
215 255 ↑19%
127 65 ↓49%
Fort McMurray
Grande Prairie
831 1003 ↑21%
424 423 ↓0%
6
158 103 ↓35%
Edmonton
32 15 ↓53%
5
4
Calgary
2062
1235
↓40%
1 2 3

Figure S5.1
New conventional gas connections, 2010, by PSAC area

■ 2009 Total = 3849 ↓19%
▨ 2010 Total = 3099

Table 5.13 Conventional gas connections by well type and PSAC area

	New connections		Recompletions		Total	
PSAC area	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Vertical/Directional wells						
1	7	23	5	7	**12**	**30**
2	643	588	178	181	**821**	**769**
3	838	1 601	172	308	**1 010**	**1 909**
4	24	67	60	80	**84**	**147**
5	148	185	198	207	**346**	**392**
6	13	39	40	78	**53**	**117**
7	106	111	103	89	**209**	**200**
Subtotal	**1 779**	**2 614**	**756**	**950**	**2 535**	**3 564**
Horizontal wells						
1	3	2	0	0	**3**	**2**
2	182	62	0	0	**182**	**62**
3	225	153	0	0	**225**	**153**
4	19	12	0	0	**19**	**12**
5	77	31	0	0	**77**	**31**
6	12	9	0	0	**12**	**9**
7	46	16	0	0	**46**	**16**
Subtotal	**564**	**285**	**0**	**0**	**564**	**285**
Total	**2 343**	**2 899**	**756**	**950**	**3 099**	**3 849**

For the past decade, conventional gas activity has been focused on the shallow gas plays in southeastern Alberta, accounting for 50 per cent of activity because of the lower cost of drilling, existing infrastructure, and short tie-in times, despite the low production rates of these connections. However, the trend is changing. In 2010, the share of new gas connections in southeastern Alberta declined by 10 per cent while the share in PSAC Area 2 increased by 10 per cent. This indicates movement by operators to the gas-liquids-rich areas of the province.

Figure S5.2 illustrates the number of producing conventional gas connections and the average daily connection productivity by PSAC area in 2010. These rates are calculated using the annual gas production volume and the number of producing gas connections for each PSAC area.

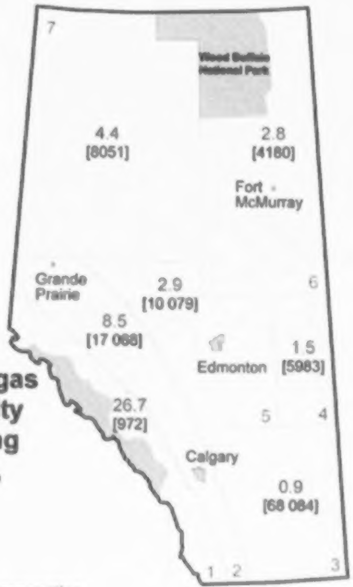

Figure S5.2
Conventional raw gas average productivity rates and producing connections, 2010, by PSAC area
10^3 m^3/d/connection
[number of connections]

2010 average = 2.9 10^3 m^3/d/connection

5.2.2.2 Coalbed Methane Connections

The ERCB identifies CBM and CBM hybrid connections using licensing data, production reporting, and detailed geological evaluations. These designations are re-evaluated annually and adjusted if required based on new information. Historical numbers are also updated annually as a result. All connections and volumes in this section are based on CBM connection designations as of December 31, 2010.

In 2010, there were 1085 new connections for CBM and CBM hybrid production: 1075 in the Horseshoe Canyon and 10 in the Mannville. New connections decreased in 2010 by 38 per cent in the Horseshoe Canyon and 55 per cent in the Mannville from the revised numbers of connections in 2009. The low price environment accounts for part of the decrease; however, the reduction is also a result of operators now reporting CBM hybrid connections as conventional gas.

New CBM and CBM hybrid connection activity for 2010 and 2009 is shown in **Table 5.14**. The table shows the number of CBM and CBM hybrid connections in vertical or directional wells and horizontal wells within the ERCB-defined CBM play and subareas. Most CBM and CBM hybrid connections in the Horseshoe Canyon Formation are in vertically drilled wells, whereas most connections into the Mannville Formation are in horizontal wells. In 2010, all Horseshoe Canyon CBM and CBM hybrid connections were vertical and all Mannville CBM connections were horizontal.

The table also breaks down the number of new CBM and CBM hybrid connections placed on production versus connections recompleted in existing wellbores and placed on production. In 2010, about 45 per cent of the new connections were recompletions into existing vertical wells in the Horseshoe Canyon formation.

Table 5.14 CBM and CBM hybrid connections by well type and CBM area

	New connections		Recompletions		Total	
CBM play subarea	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Vertical/directional wells						
Horseshoe Canyon						
1	132	272	203	108	**335**	**380**
2	1	17	28	22	**29**	**39**
3	78	268	23	36	**101**	**304**
4	178	367	63	127	**241**	**494**
5	5	12	16	3	**21**	**15**
6	29	39	29	20	**58**	**59**
7	72	131	32	54	**104**	**185**
Mannville Corbett	0	6	0	0	**0**	**6**
Undefined[a]	96	41	90	192	**186**	**233**
Subtotal	**591**	**1 153**	**484**	**562**	**1 075**	**1 715**
Horizontal wells						
Horseshoe Canyon						
1	0	0	0	0	**0**	**0**
2	0	0	0	0	**0**	**0**
3	0	2	0	0	**0**	**2**
4	0	6	0	0	**0**	**6**
5	0	0	0	0	**0**	**0**
6	0	0	0	0	**0**	**0**
7	0	1	0	0	**0**	**1**
Mannville Corbett	5	18	0	0	**5**	**18**
Undefined[a]	5	5	0	0	**5**	**5**
Subtotal	**10**	**32**	**0**	**0**	**10**	**32**
Total	**601**	**1 185**	**484**	**562**	**1 085**	**1 747**

[a] Includes connections outside defined play subarea boundaries.

Figure S5.3 shows the 2010 average productivity rates for CBM and CBM hybrid producing connections by CBM play and subareas. In 2010, the 2062 CBM and CBM hybrid connections located outside of the

ERCB-defined CBM play subareas had a total production of 1.8 10^6 m^3/d (0.88 $10^3 m^3$/d/connection) and are grouped as undefined.

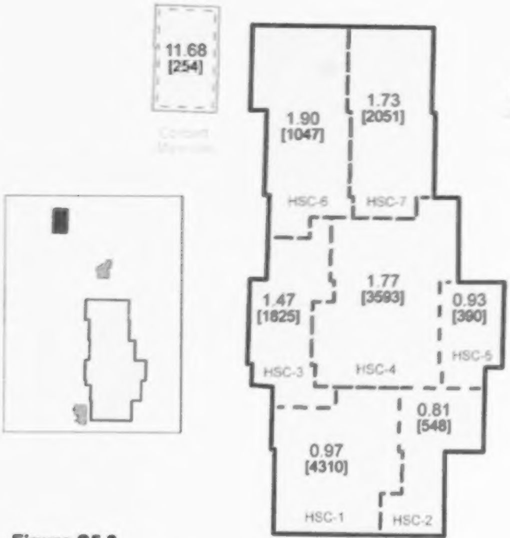

Figure S5.3

2010 CBM and CBM hybrid average productivity rates and producing connections by CBM plays and subareas

10^3 m^3/d/connection
[number of connections]

2010 average = 1.52 10^3 m^3/d/connection
16 080 connections

5.2.2.3 Shale Connections

The ERCB identifies shale gas connections using the designation submitted by the operator to the Petroleum Registry of Alberta. These designations are continually evaluated and adjusted if required based on new information, resulting in revisions to historical annual numbers. All shale gas connections and volumes in this section are based on current designations as of December 31, 2010.

The ERCB currently recognizes 142 producing shale and commingled shale gas connections in 2010. Horizontal gas wells drilled in tight gas formations in northwest Alberta are reported as conventional gas reserves; however, the extension of the play into B.C. becomes shalier and is defined as shale gas. Reserves associated with this development are included in the conventional gas category in this report.

Most producing shale gas connections in Alberta are shallow vertical wells. **Table 5.15** identifies the types of shale gas connections in 2010 and 2009. About 73 per cent of the designated shale gas connections have been in the last three years with most in 2008. Recompletions into shale gas producing formations from existing wells are common in this low natural gas price environment; the gas is commingled in the wellbore with conventional gas and/or CBM production from other formations.

Table 5.15 Shale gas connections by well type

	New Connections		Recompletions		Total	
Well type	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Vertical wells	11	9	10	2	21	11
Horizontal wells	4	1	0	0	4	1
Total	**15**	**10**	**10**	**2**	**25**	**12**

The 2010 average daily productivity rate for all producing shale gas connections was 1.8 $10^3 m^3$/d and the three-year average initial daily productivity rate was 1.9 $10^3 m^3$/d. The average initial daily rate is calculated using the average of the first full calendar year of production for the most recent three years.

5.2.3 Production Trends

5.2.3.1 Conventional Gas

Figure S5.4 illustrates historical conventional marketable gas production including gas from oil wells by PSAC area. Production in all areas of the province decreased from 2009 to 2010. The top three producing areas in the province—PSAC Area 2 (Foothills Front), PSAC Area 3 (southeastern Alberta), and PSAC Area 7 (northwestern Alberta)—are responsible for 38 per cent, 20 per cent, and 11 per cent of gas production in 2010, respectively.

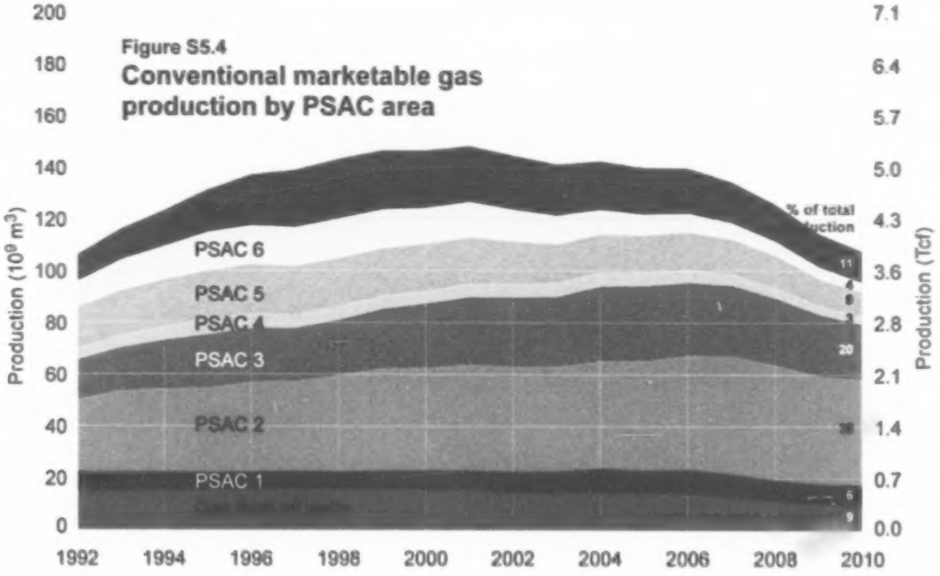

Figure S5.4
Conventional marketable gas production by PSAC area

Figure S5.5 shows that from 1992 to 2009, the numbers of producing conventional gas connections have increased while gas production has decreased since reaching its peak in 2001. The numbers of new conventional gas connections each year had not been adequate to offset production declines in existing connections.

In 2010, conventional gas well connections declined to 114 269 after reaching a high of 115 443 in 2009. This is the first year in recent history in which the number of producing conventional gas well connections declined from the previous year.

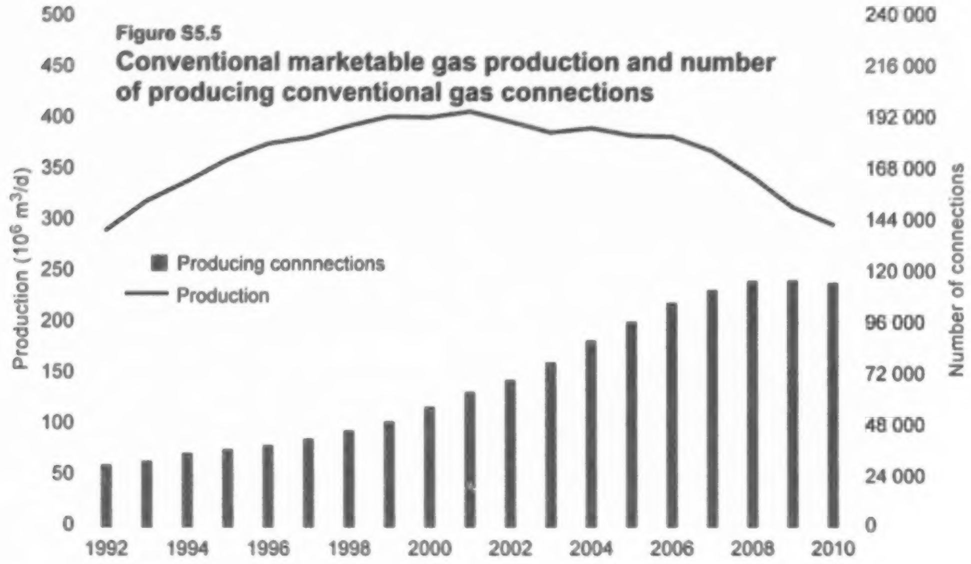

Figure S5.5

Conventional marketable gas production and number of producing conventional gas connections

Historical conventional raw gas production by connection year is presented in **Figure S5.6**. Natural gas production from oil wells has remained relatively stable, as shown by the band on the bottom of the chart. Each band above the gas production from oil wells represents production from new conventional gas connections by year. The percentages on the right-hand side of the figure represent the areas' shares of total production from conventional gas connections in 2010. About 8 per cent of conventional gas production in 2010 came from the connections in 2010. Connections before 2000 contributed 29 per cent of gas production in 2010.

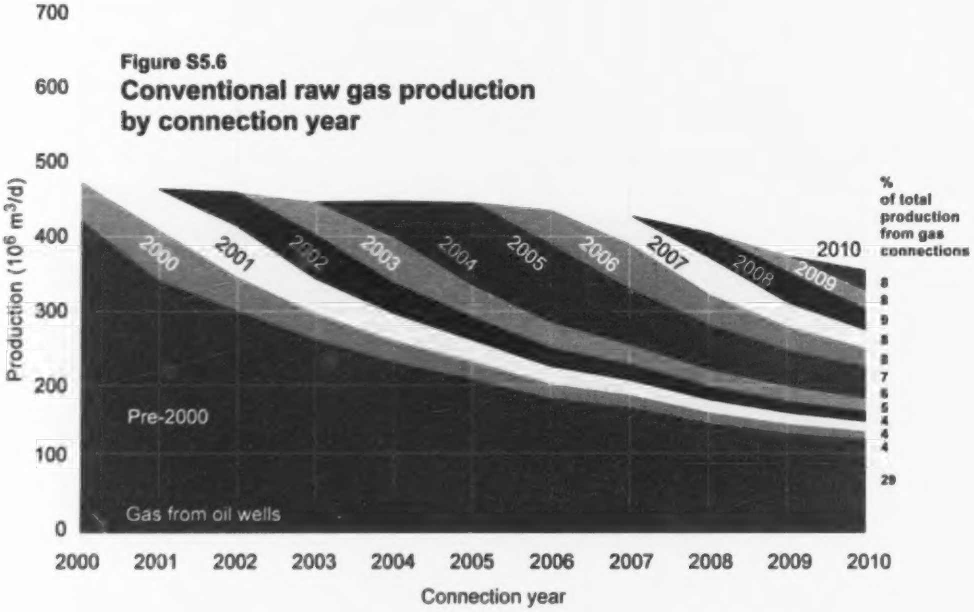

Figure S5.6

Conventional raw gas production by connection year

The percentage of sour gas relative to total gas production decreased from 31 per cent in 2000 to 21 per cent in 2010 because of the decline in production from the large sour gas pools in the province.

Figure S5.7 compares total raw natural gas production in Alberta with both Texas and Louisiana onshore production and total U.S. gas production over the past 50 years.[5] Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta's production has a noticeably flatter production profile, peaking in 2001. For both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production, but after a decade of decline, production rates stabilized. Only recently has Texas seen an increase again in gas production because of growth in shale gas production from the Barnett, Haynesville, and Eagle Ford shale plays.

The long-term outlook for North American gas supply has changed with the recent growth in supply from shale gas production. With the success of the Barnett and Eagle Ford shales in Texas and the expected potential of other shale gas plays in the U.S., particularly the Marcellus, Woodford, and Fayetteville shales, as well as the Horn River and Montney shale plays in northeastern B.C., shale gas production will continue to grow and become a significant source of natural gas.

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[5] Data used to determine U.S. data production is from the EIA. Includes both conventional and unconventional production.

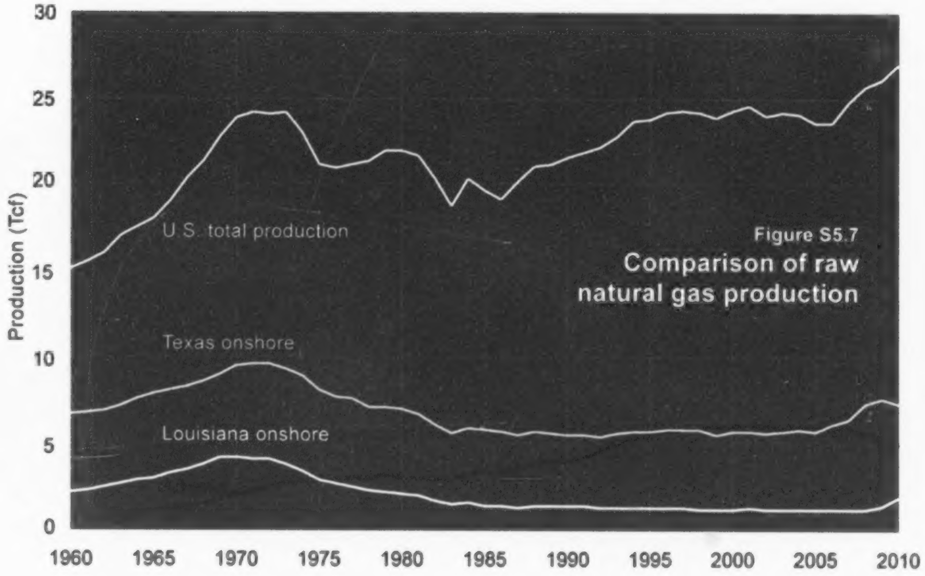


Figure S5.7
Comparison of raw natural gas production

5.2.3.2 Coalbed Methane

Total CBM and CBM hybrid production and numbers of producing connections are shown in **Figure S5.8.** This figure shows that the production contribution from the Mannville CBM connections accounts for 13 per cent of the total CBM produced, but from only 2.4 per cent of the total producing CBM connections. The chart illustrates the much higher productivity rates of the horizontal Mannville CBM connections compared with the vertical CBM and CBM hybrid Horseshoe Canyon connections.

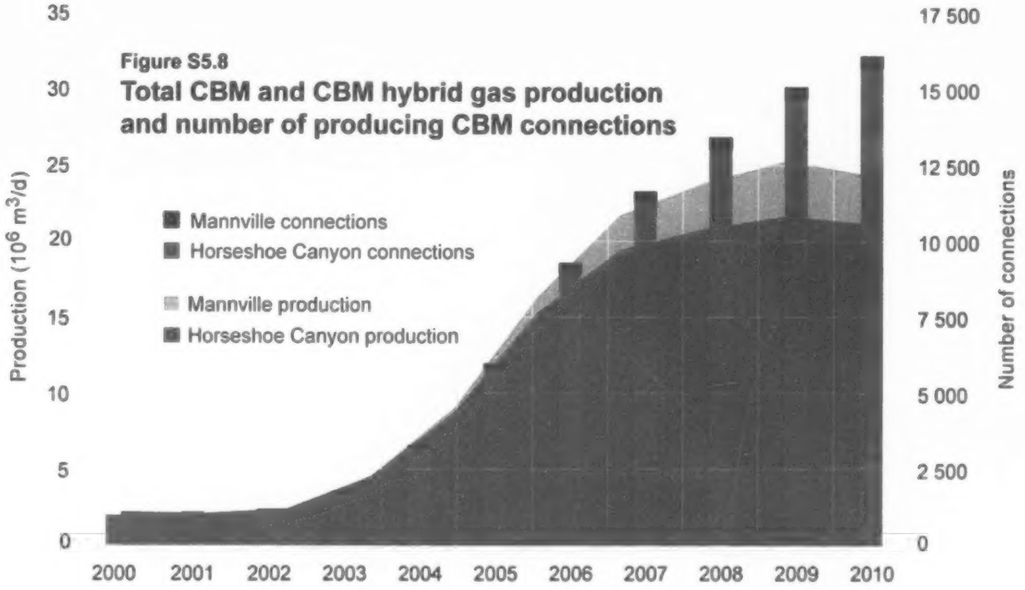
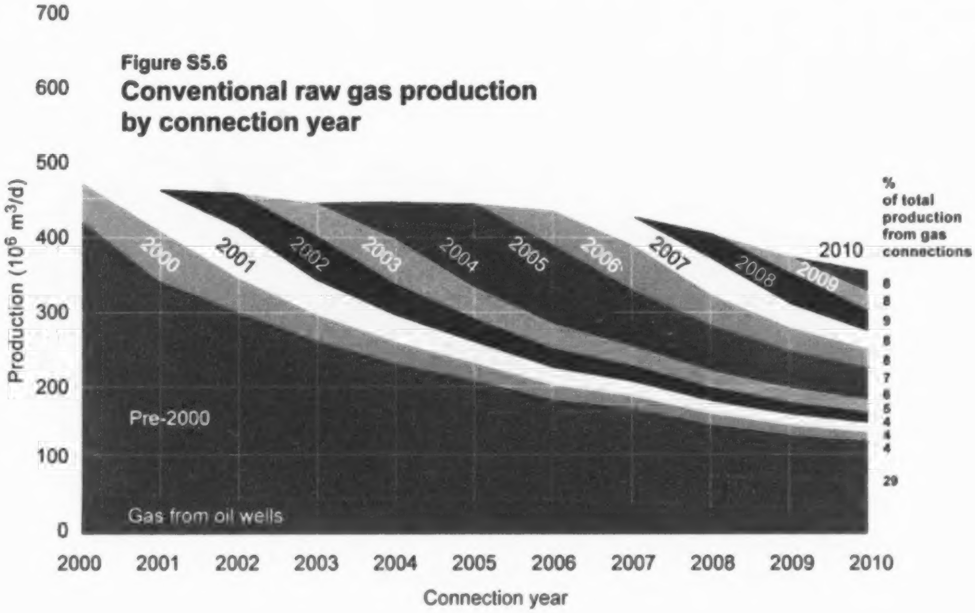


Figure S5.8
Total CBM and CBM hybrid gas production and number of producing CBM connections



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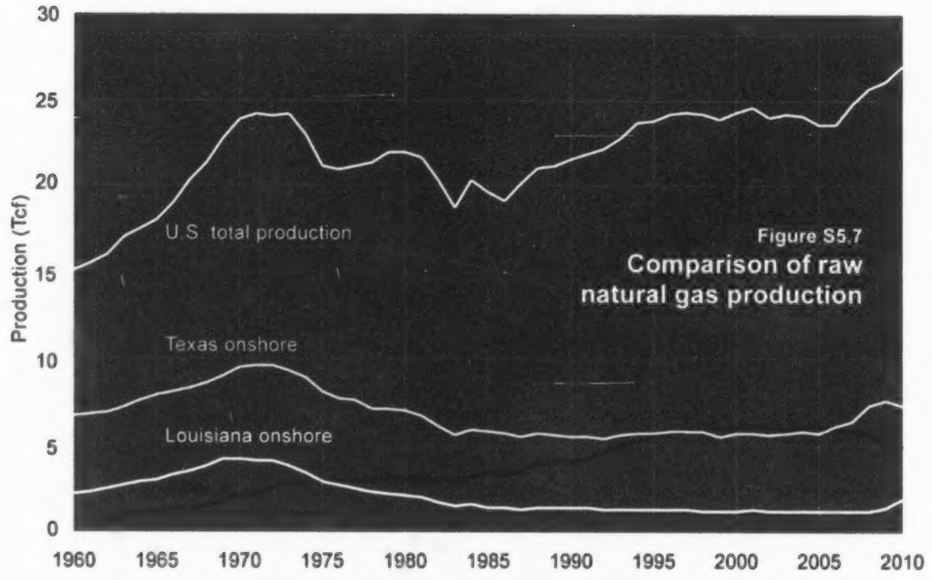

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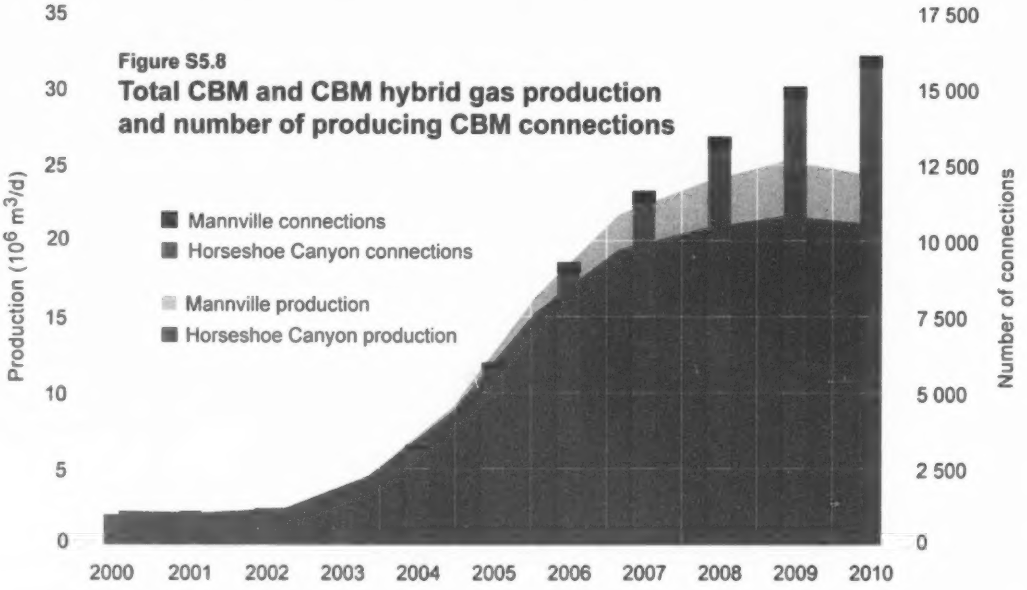

Figure S5.8
Total CBM and CBM hybrid gas production and number of producing CBM connections

Although these high productivity rates would normally indicate resource development, there have been low activity levels in the Mannville CBM play due to the limited number of industry participants in the area, the high cost of development and maintenance, and the low gas price environment.

Figure S5.9 shows the historical breakdown of CBM and CBM hybrid connections into categories of vertical or directional wells, recompletions into existing wells, and horizontal wells. The percentage of CBM connections that are in vertical wells as recompletions has increased from 5 per cent to 45 per cent over the past decade.

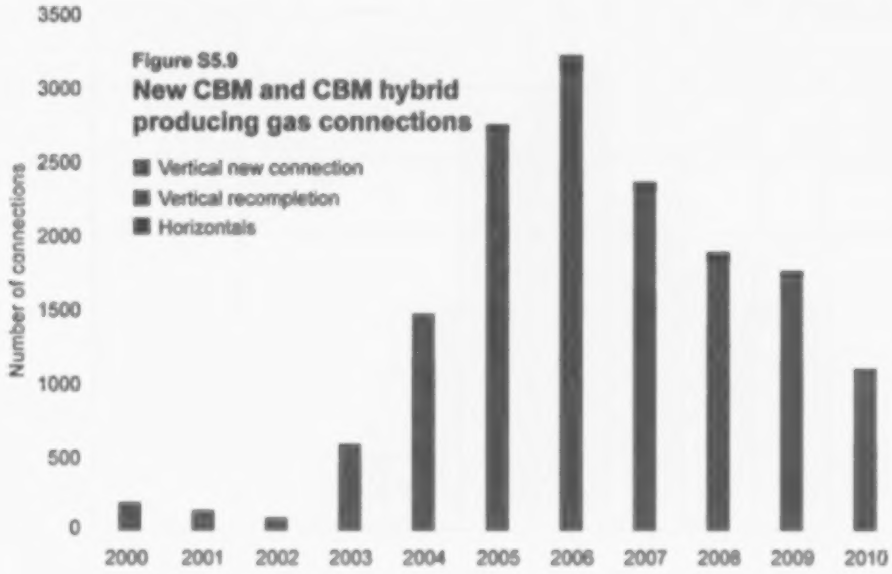

Figure S5.9
New CBM and CBM hybrid producing gas connections

5.2.3.3 Shale Gas

Shale gas production in Alberta is shown in **Figure S5.10** along with the number of producing shale gas connections in each year.

5.2.4 Production Characteristics of New Connections

5.2.4.1 Conventional Gas

As shown in **Figure S5.11**, 75 337 producing gas connections, or about 58 per cent, produce less than 1.0 10^3 m^3/d of raw gas. In 2010, these gas connections produced at an average rate of 0.5 10^3 m^3/d and contributed less than 9 per cent of the total natural gas production.

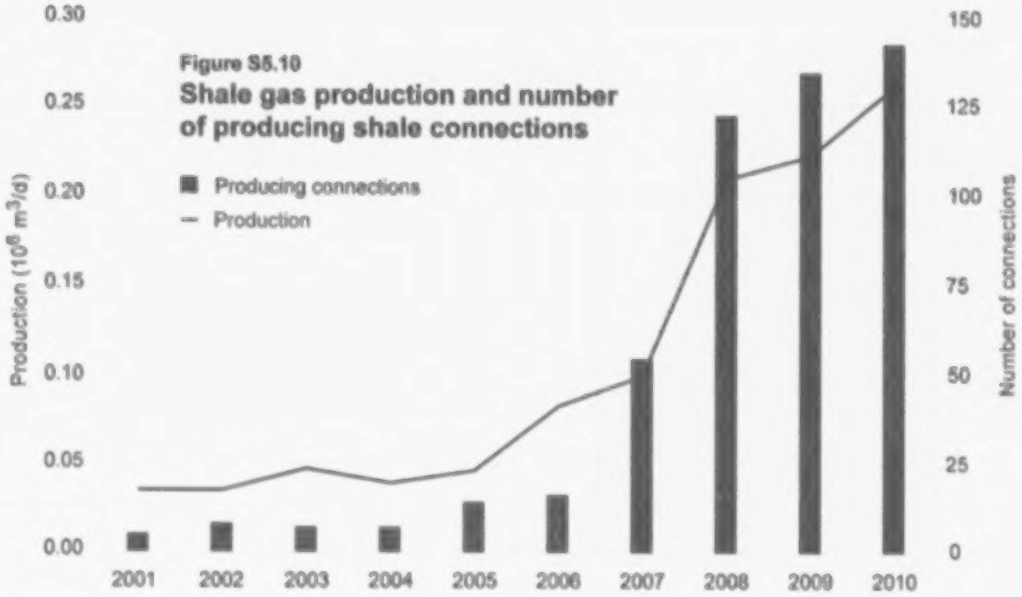

Figure S5.10
Shale gas production and number of producing shale connections

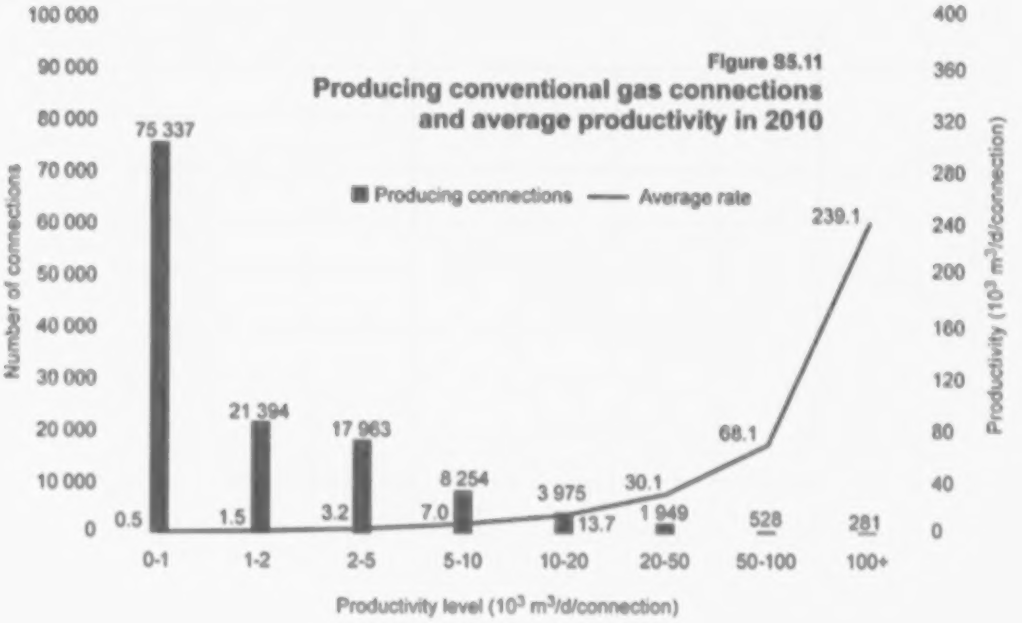

Figure S5.11
Producing conventional gas connections and average productivity in 2010

Less than 1 per cent of the conventional gas connections produced at rates over 50 10^3 m^3/d, but they contributed 26 per cent to total production. New horizontal gas wells with high gas rates are responsible for increasing the share of total gas production from wells in this category of well productivity by 7 per cent, up from 19 per cent in 2009.

Average initial productivities of new conventional gas connections in some areas of the province are higher than in past years. **Figure S5.12** shows the average initial productivity of new connections by connection year for the province and for wells in PSAC Area 3 (southeastern Alberta) and in PSAC Area 2 (Foothills). The productivities have been adjusted for surface losses to reflect sales gas rates as opposed to raw gas rates shown in the previous chart. Initial average daily production rates are calculated using the first full calendar year of production for gas connections. Average initial productivities for new connections, excluding southeastern Alberta, are shown in the figure.

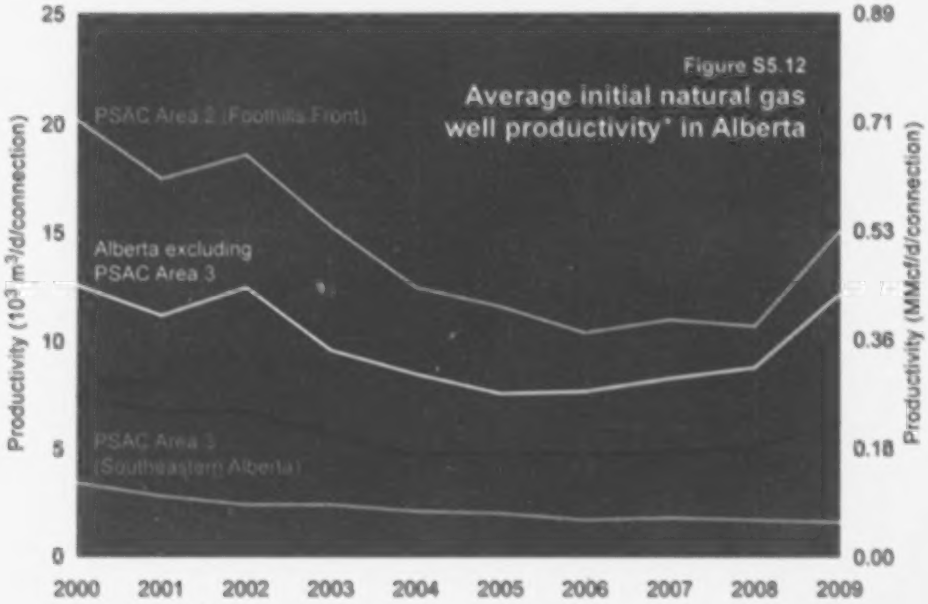
Figure S5.12
Average initial natural gas well productivity* in Alberta

* Adjusted for surface loss.

This chart illustrates the improvement in average initial productivities of recent connections. This is a result of horizontal drilling and new completion techniques. Average initial well productivities increased in all areas of the province with the exception of PSAC Area 1 (Foothills), PSAC Area 3 (southeastern Alberta), and PSAC Area 6 (northeastern Alberta).

Figure S5.13 shows average initial productivities for wells by well type for wells connected in 2009 in areas of the province in which initial productivities have increased year over year as a result of horizontal drilling.

Figure S5.14 shows typical gas production profiles for vertical and horizontal wells in the Kaybob South field that are producing commingled gas from the Bluesky, Gething, Nordegg, and Montney formations. Wells that were placed on production within the 2008 to 2010 time period were used to illustrate the difference in production profiles by well type. Initial well productivities of horizontal wells that are completed using multistage fracturing technology are significantly higher than initial well productivities of vertical wells. New horizontal wells have much higher initial well productivities than vertical wells, as illustrated earlier in **Figure S5.13**, and they continue to produce at much higher rates over the first 18 months of production.

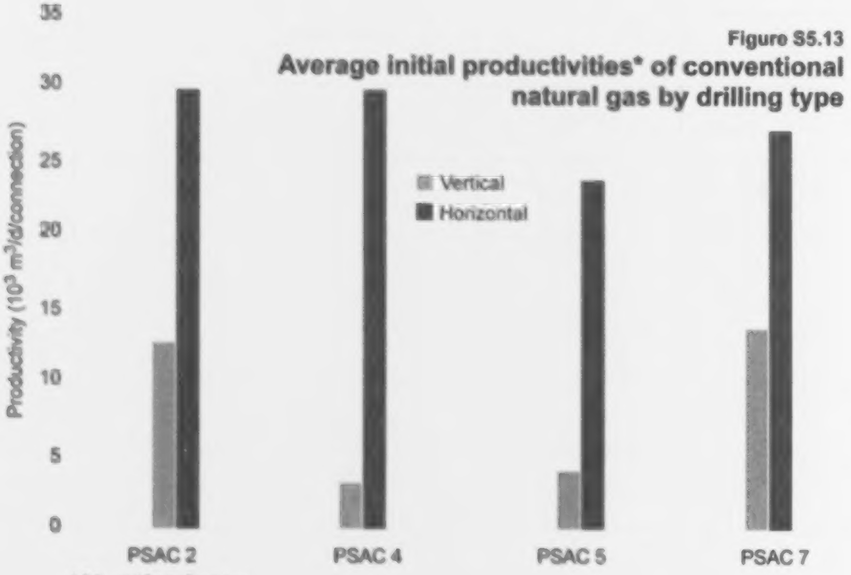

Figure S5.13
Average initial productivities* of conventional natural gas by drilling type

* Adjusted for surface loss

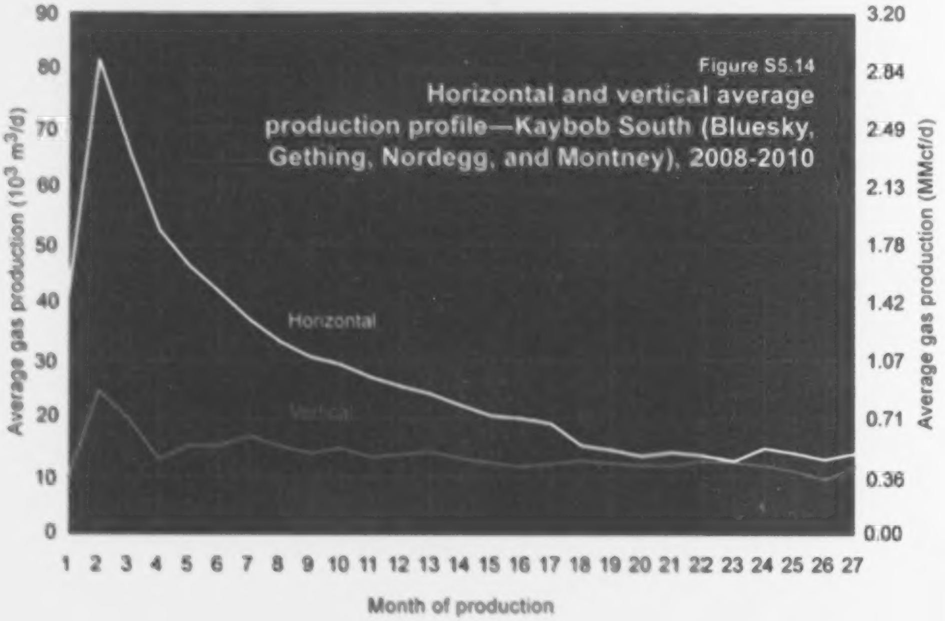

Figure S5.14
Horizontal and vertical average production profile—Kaybob South (Bluesky, Gething, Nordegg, and Montney), 2008-2010

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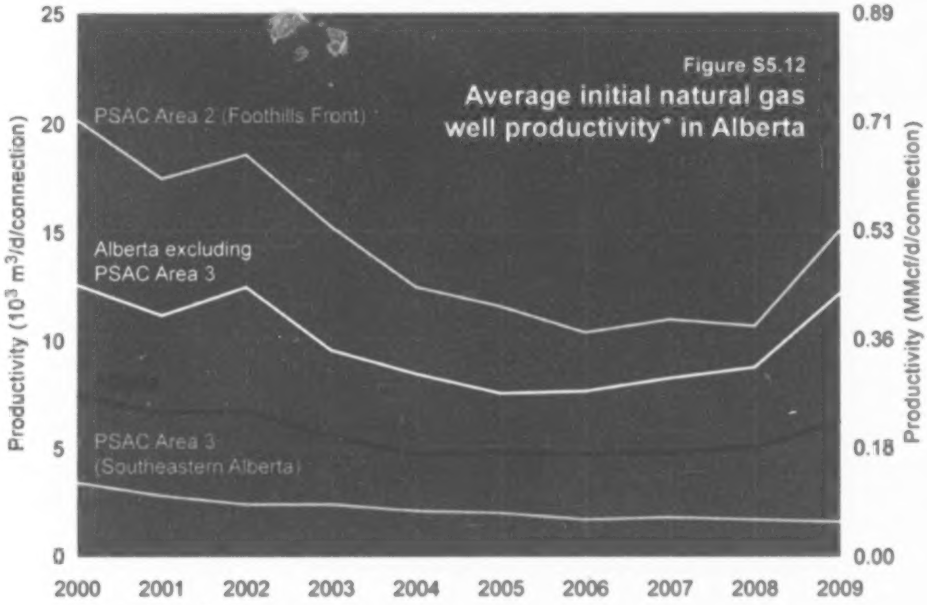
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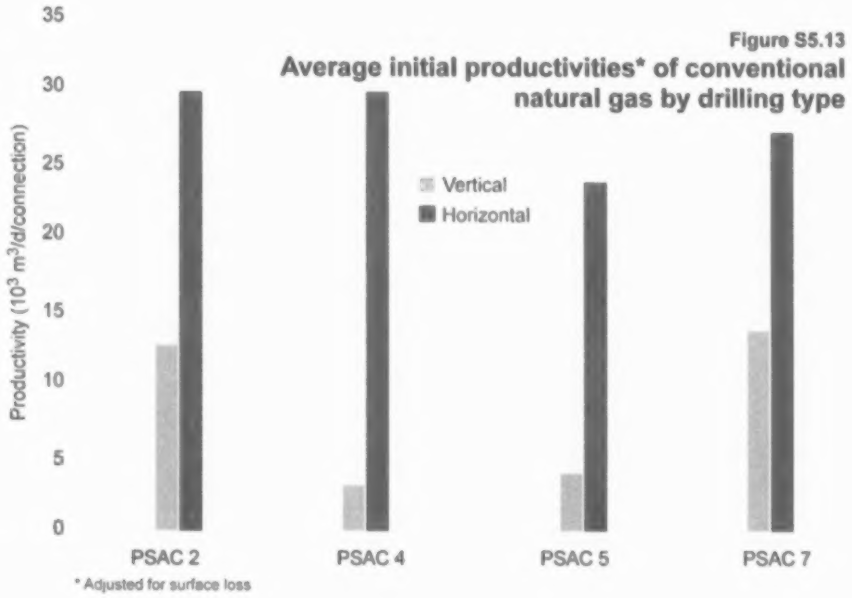

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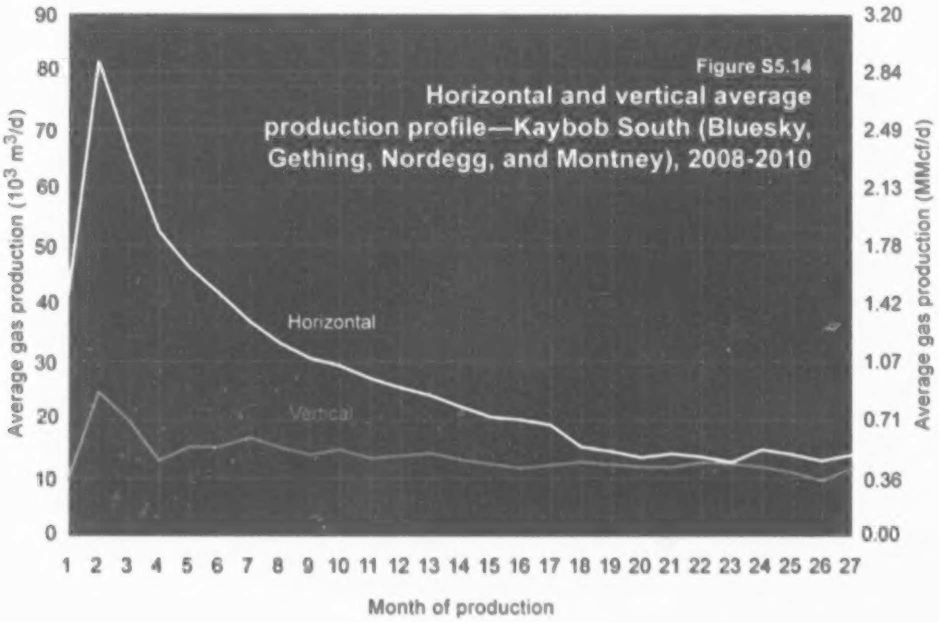


Figure S5.14
Horizontal and vertical average production profile—Kaybob South (Bluesky, Gething, Nordegg, and Montney), 2008-2010

Figure S5.15 shows production profiles of gas produced from vertical and horizontal oil wells in the Garrington field that are producing crude oil and gas from the Cardium Formation. Gas connections that were placed on production within the 2008 to 2010 period were used to illustrate the difference in production profiles by well type. Horizontal drilling combined with multistage fracturing technology has significantly improved well productivity. New horizontal oil wells have much higher initial well productivities for crude oil and for solution gas than do vertical wells, as illustrated in the chart.

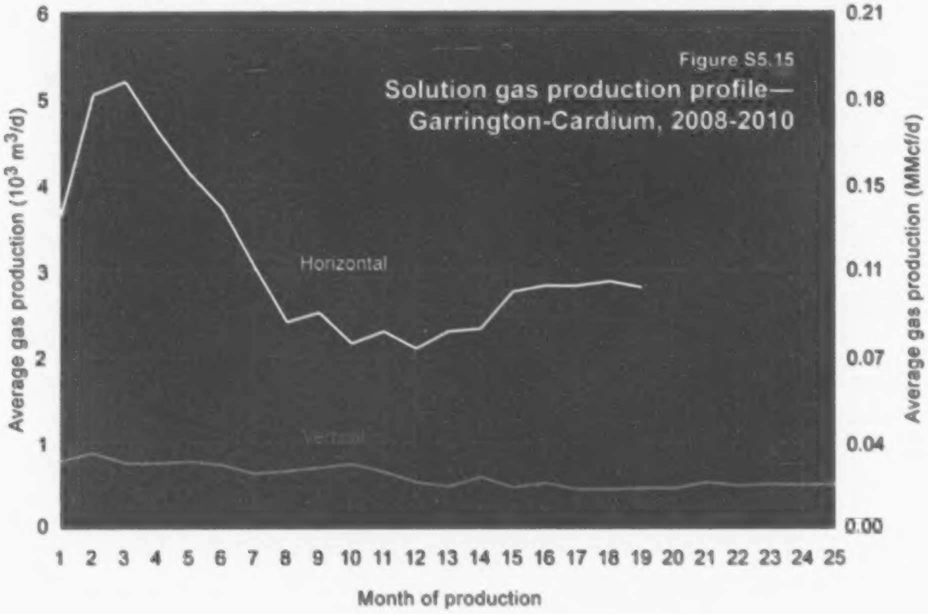
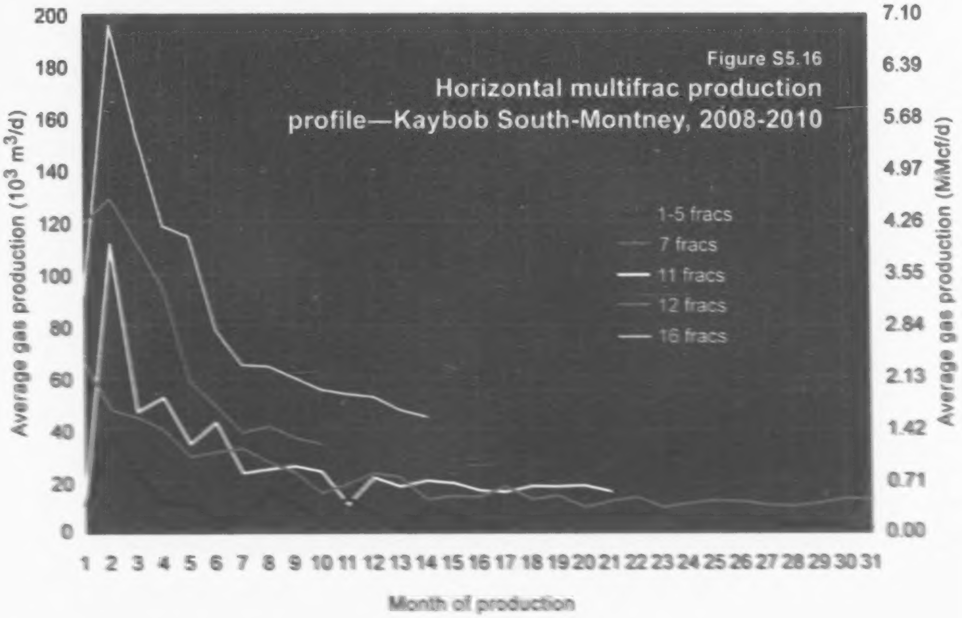


Figure S5.15
Solution gas production profile—Garrington-Cardium, 2008-2010

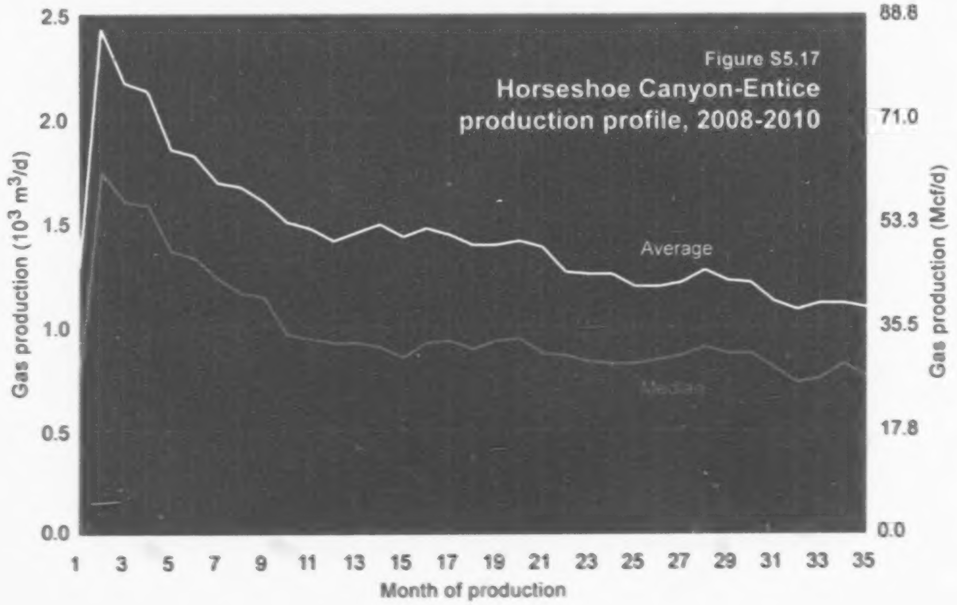
The provincial forecast for natural gas produced from crude oil wells assumes that production will continue to decline over time. The ERCB will be reviewing gas production information from crude oil wells to determine if this trend might be changing as crude oil production increases.

The final series of production profiles shown in **Figure S5.16** illustrates the impact of new completion technologies on initial well productivities. Wells completed with multistage fracturing technology were selected to illustrate the impact that the number of fractures has on average initial production rates in this play area. For this series of wells, the number of fractures completed in the wellbore affects the production profile. Generally, the more fractures a well has, the higher the production profile. For example, wells with 16 fractures in the wellbore have an average production profile that is higher than the average profile of wells that have had 11 fractures, and the production rate appears to stabilize at nearly double the rate after 12 months.



5.2.4.2 Coalbed Methane

Figure S5.17 shows the normalized average and median production profiles for typical CBM and CBM hybrid Horseshoe Canyon wells in the Entice field (subarea 1).



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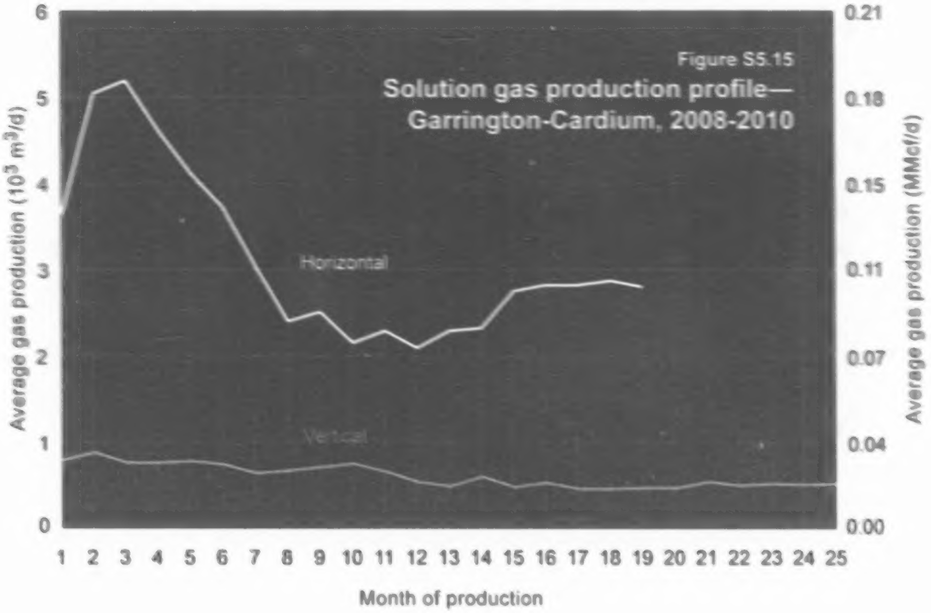
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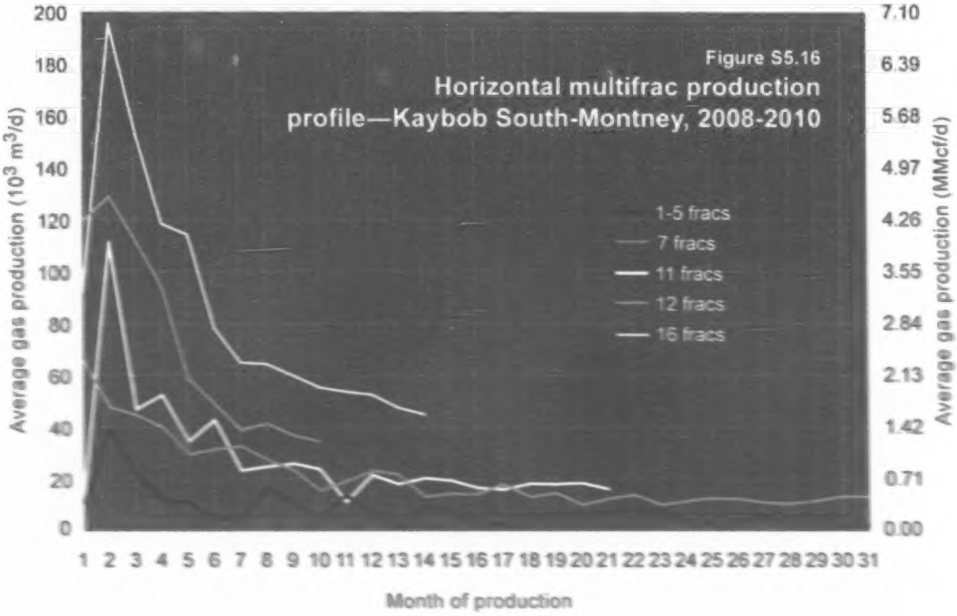

Figure S5.16

Horizontal multifrac production profile—Kaybob South-Montney, 2008-2010

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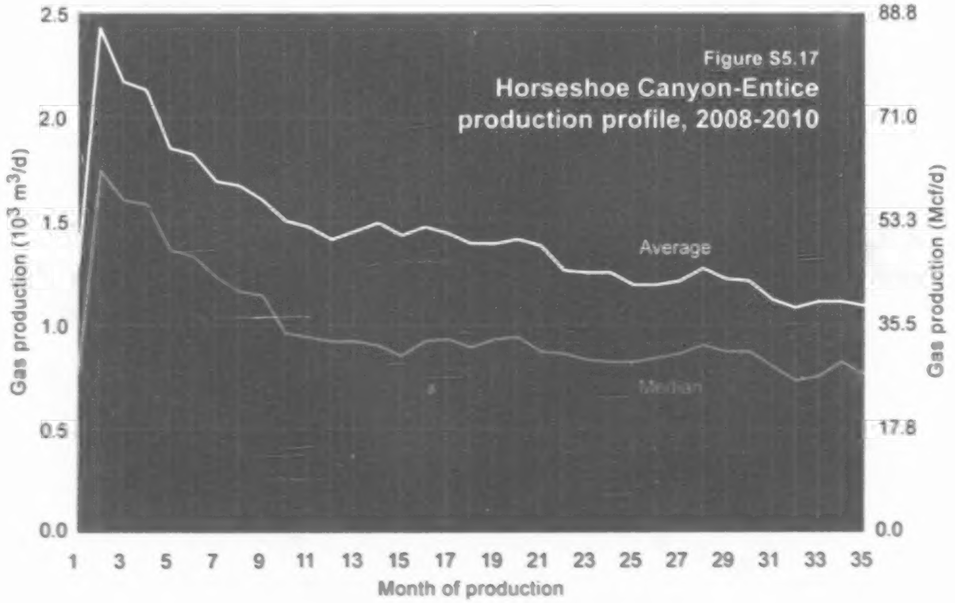
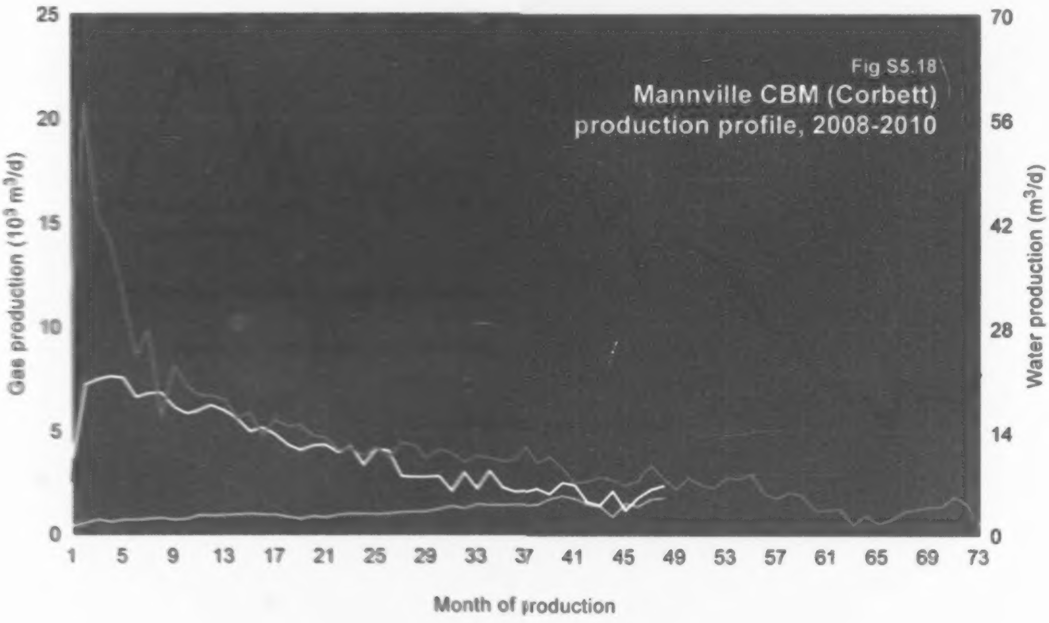


Figure S5.17

Horseshoe Canyon-Entice production profile, 2008-2010

Figure S5.18 shows the average normalized production profiles for gas and water production in the Corbett Mannville area. Horizontal multilateral drilling techniques applied to the Mannville coal seams has improved gas production rates compared with vertical and directionally drilled wells. Horizontal wells also hasten the dewatering period and produce at much higher initial productivity rates.



5.2.4.3 Shale Gas

The Colorado shale in east-central Alberta, particularly in the Wildmere area, is where most shale development has occurred in the province to date. **Figure S5.19** shows the normalized average and median production profiles for a typical Wildmere area Colorado shale gas connection. This area has slightly lower productivity rates than the provincial average because it is a shale-only area and because the provincial rate is influenced by commingling with CBM and conventional gas.

5.2.5 Marketable Natural Gas Production—Forecast

In projecting conventional gas and CBM supply, the ERCB considers three components: expected production from existing conventional gas and CBM connections, expected production from new conventional gas and CBM connections in new and existing wells, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be-established reserves of conventional natural gas in the province. As shale gas development is in its early stages in Alberta, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time.

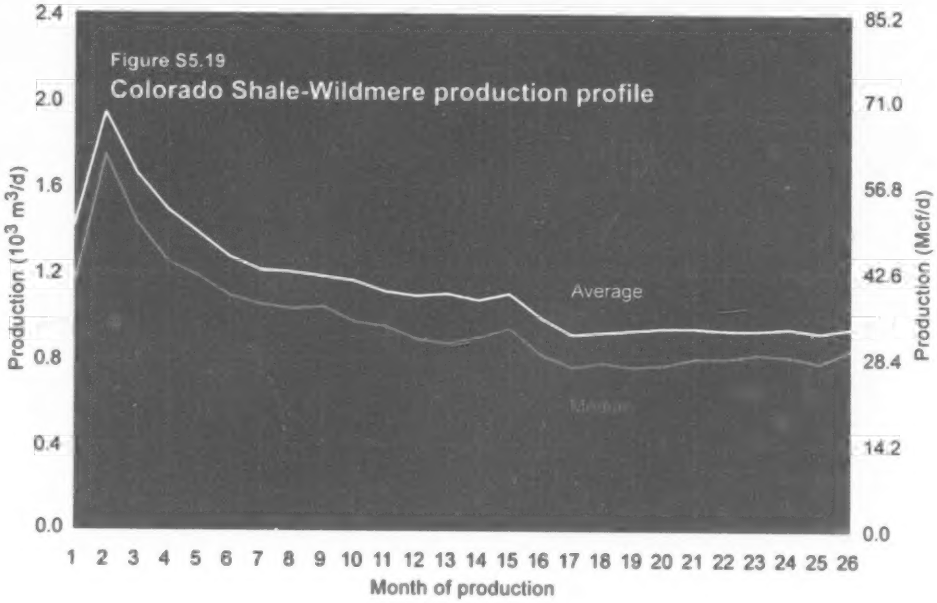


Figure S5.19
Colorado Shale-Wildmere production profile

To forecast gas production, production from existing wells and from new wells drilled and connected each year has been analyzed. The number of new connections and the average productivity of the wells are the main determining factors used in projecting natural gas production volumes over the forecast period.

5.2.5.1 Conventional Gas

To project natural gas production from conventional gas connections from before 2011, the ERCB assumes the following:

- Gas production from existing conventional gas connections at year-end 2010, based on observed performance, is assumed to decline by 16 per cent per year over the forecast period.
- Production from existing conventional gas connections will be 232.1 10^6 m^3/d in 2011.

Over the forecast period, production of conventional gas from existing gas wells is expected to decline from 232.1 10^6 m^3/d to 47.4 10^6 m^3/d.

To project natural gas production from new conventional gas connections, the ERCB considered the following assumptions:

- The numbers of new conventional gas connections over the forecast period are projected to be 3300 in 2011, 3650 in 2012, 4000 in 2013, and 4500 from 2014 to 2020.

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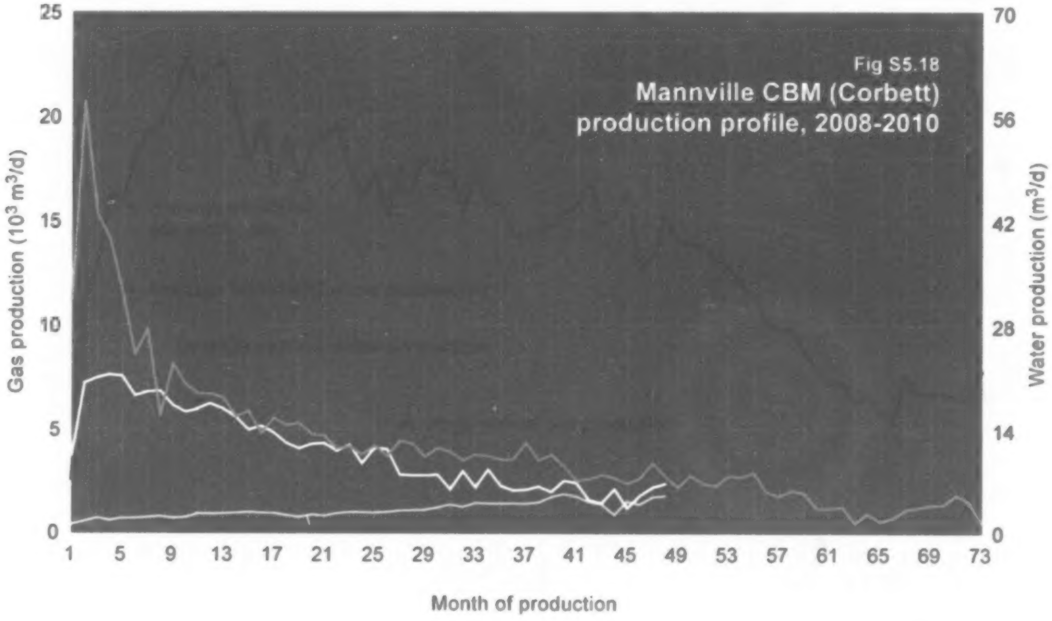

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5.2.5 Marketable Natural Gas Production—Forecast

In projecting conventional gas and CBM supply, the ERCB considers three components: expected production from existing conventional gas and CBM connections, expected production from new conventional gas and CBM connections in new and existing wells, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be-established reserves of conventional natural gas in the province. As shale gas development is in its early stages in Alberta, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time.

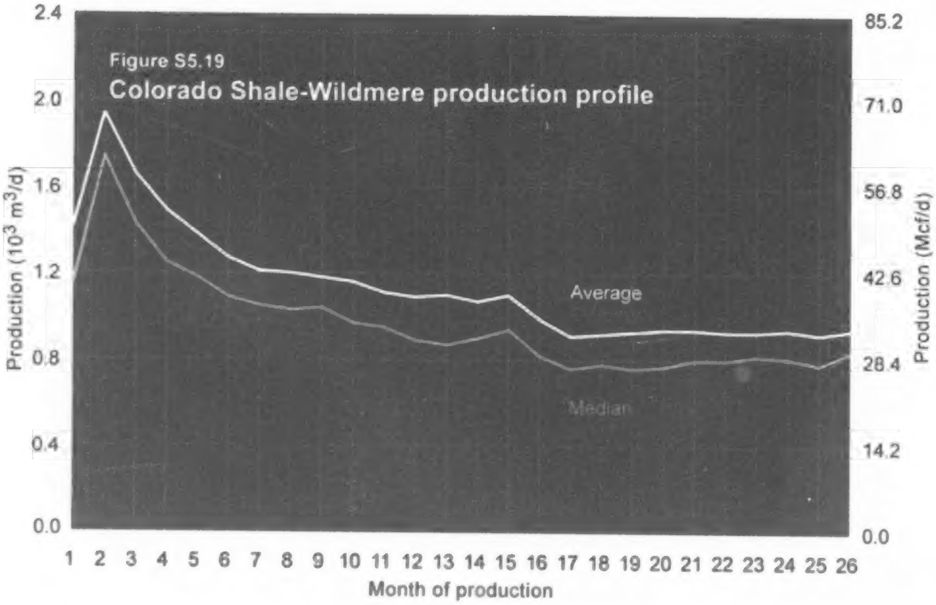


Figure S5.19
Colorado Shale-Wildmere production profile

To forecast gas production, production from existing wells and from new wells drilled and connected each year has been analyzed. The number of new connections and the average productivity of the wells are the main determining factors used in projecting natural gas production volumes over the forecast period.

5.2.5.1 Conventional Gas

To project natural gas production from conventional gas connections from before 2011, the ERCB assumes the following:

- Gas production from existing conventional gas connections at year-end 2010, based on observed performance, is assumed to decline by 16 per cent per year over the forecast period.
- Production from existing conventional gas connections will be 232.1 10^6 m^3/d in 2011.

Over the forecast period, production of conventional gas from existing gas wells is expected to decline from 232.1 10^6 m^3/d to 47.4 10^6 m^3/d.

To project natural gas production from new conventional gas connections, the ERCB considered the following assumptions:

- The numbers of new conventional gas connections over the forecast period are projected to be 3300 in 2011, 3650 in 2012, 4000 in 2013, and 4500 from 2014 to 2020.

- Conventional gas connections in southeastern Alberta will represent 40 per cent of all new conventional gas connections in 2010 and will decline to 35 per cent of new connections each year over the forecast period.
- The average initial productivity of a new conventional gas connection in southeastern Alberta will be 1.5 10^3 m^3/day.
- The average initial productivity of a new conventional gas connection in the rest of the province will be 8.5 10^3 m^3/day in 2011, increasing to 9.5 10^3 m^3/day by 2012, then decreasing to 8.0 10^3 m^3/day by 2020.
- Production from new gas wells will decline by 33 per cent in the first year, 24 per cent in the second year, 18 per cent in the third year, and 16 per cent in the fourth year and thereafter.
- Gas production from oil wells, based on observed performance, is assumed to decline by 3 per cent per year over the forecast period.

Based on the remaining established and yet-to-be-established reserves and the assumptions described above, the ERCB forecasts conventional marketable gas production to 2020. The production of marketable gas from conventional reserves is expected to decrease from 294.0 10^6 m^3/d in 2010 to 188.8 10^6 m^3/d by 2020. These volumes are higher than forecast last year because new conventional gas connections are expected to have higher initial well productivities than previously forecast.

If conventional natural gas production rates follow the projection, Alberta will have recovered 79 per cent of the 6528 10^9 m^3 conventional ultimate potential[8] by 2020.

5.2.5.2 Coalbed Methane

In projecting CBM supply, the ERCB considers expected production from existing CBM connections and expected production from new CBM connections. These new connections include CBM connections into new wells drilled and recompletions into existing wells. Continual reclassification of CBM connections results in revisions to historical data and, therefore, changes to annual forecasts.

To project production from existing CBM and CBM hybrid connections before 2011, the ERCB assumes the following:

- All gas production from identified CBM and hybrid connections is included.
- All existing CBM- and hybrid-producing connections are expected to decline annually based on historical trends.

---

[8] Ultimate potential at 37.4 MJ/m³.

Over the forecast period, production of CBM and CBM hybrid wells is expected to decline from 22.4 10^6 m^3/d to 12.4 10^6 m^3/d.

To project production from new CBM and CBM hybrid connections, the ERCB assumed the following:

- Over the forecast period, CBM production will be from the Horseshoe Canyon and Mannville formations only.
- The number of new CBM and CBM hybrid connections in the Horseshoe Canyon will be 1200 connections per year over the forecast period, slightly higher than 2010 levels.
- The percentage of recompletions in existing wells versus new connections within the Horseshoe Canyon play will remain at 2010 levels over the forecast period.
- The number of Mannville CBM connections will be 10 connections per year from 2011 to 2013, and in conjunction with improved natural gas prices, connections will increase to 15 in 2014 and remain at this level until 2017. From 2017 to 2020, there will be 20 connections per year.

It is currently unclear whether the Corbett Mannville Formation will become a major commercial natural gas play. The ERCB's estimate of initial gas in place decreased substantially in 2010 for this formation. Furthermore, new connections in the area have lower initial productivity rates than reported in previous years, and well activity levels are also down.

Figure S5.20 illustrates the ERCB's forecast of CBM production to 2020. Production from CBM connections, which includes commingled production from conventional gas formations, is expected to increase from 24.4 10^6 m^3/d in 2010 to 28.5 10^6 m^3/d by 2020. In 2010, CBM production contributed 7.7 per cent of the total Alberta marketable gas production, and it is projected to contribute 13.1 per cent of the total Alberta marketable gas production in 2020. CBM and hybrid gas production is expected to be primarily from the Horseshoe Canyon over the forecast period.

5.2.5.3 Shale Gas

As mentioned earlier, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time. The economic viability of shale development in Alberta is currently unclear; however, it has the potential to become a significant supply source in Alberta. Commercial shale gas production is in its infancy and it will take time to establish the producibility of the resource. The pace of shale gas development will be affected by the natural gas price environment, supply costs, and technology.

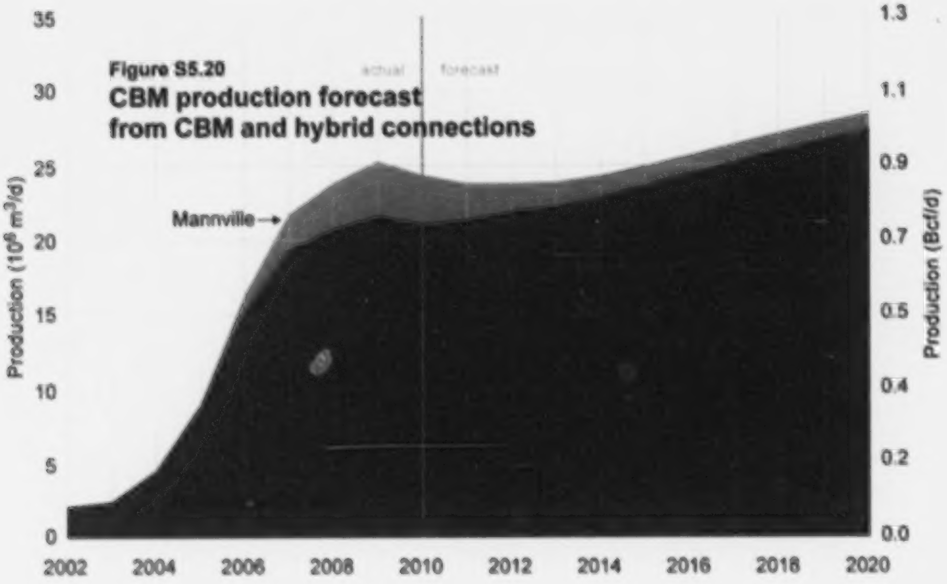


Figure S5.20
CBM production forecast from CBM and hybrid connections

5.2.5.4 Total Gas Production

The ERCB's forecast of conventional gas and CBM production to 2020 is shown in **Figure S5.21**.

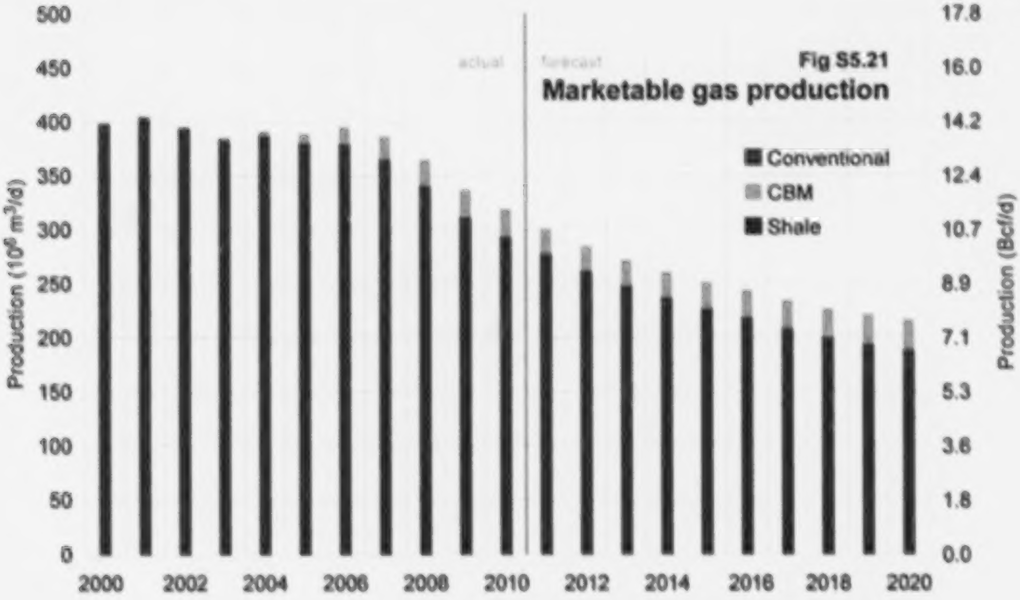


Fig S5.21
Marketable gas production

2010 volumes for shale gas production is included in the chart, shale gas production has not been forecast.

Figure S5.22 illustrates historical and forecast new connections from conventional gas and coalbed methane wells along with plant gate gas prices. (See Section 1 for discussion on price forecasts).

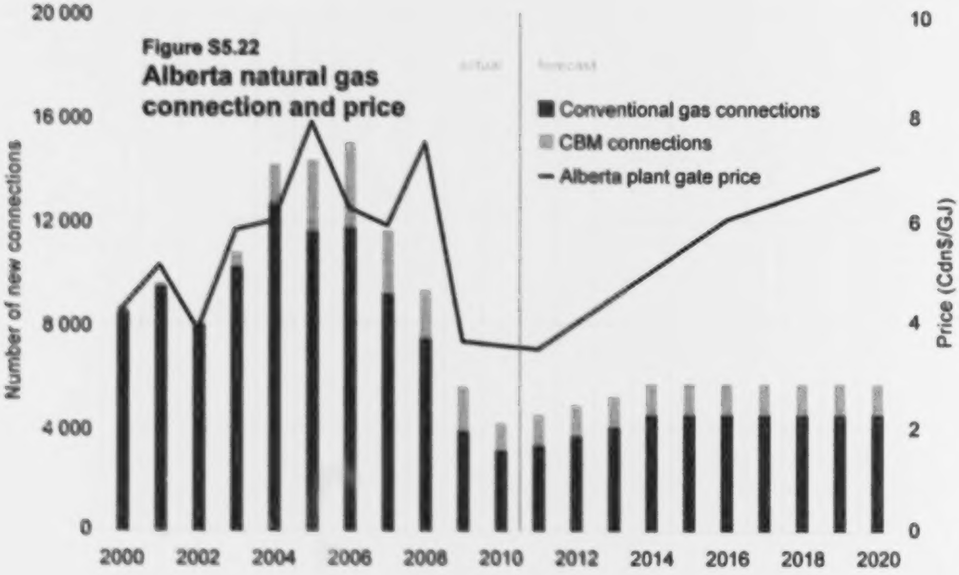


Figure S5.22
Alberta natural gas connection and price

Figure S5.23 shows process gas production (rich in liquids) from bitumen upgrading operations and raw natural gas from bitumen wells. Gas from these sources is used primarily as fuel in oil sands development.

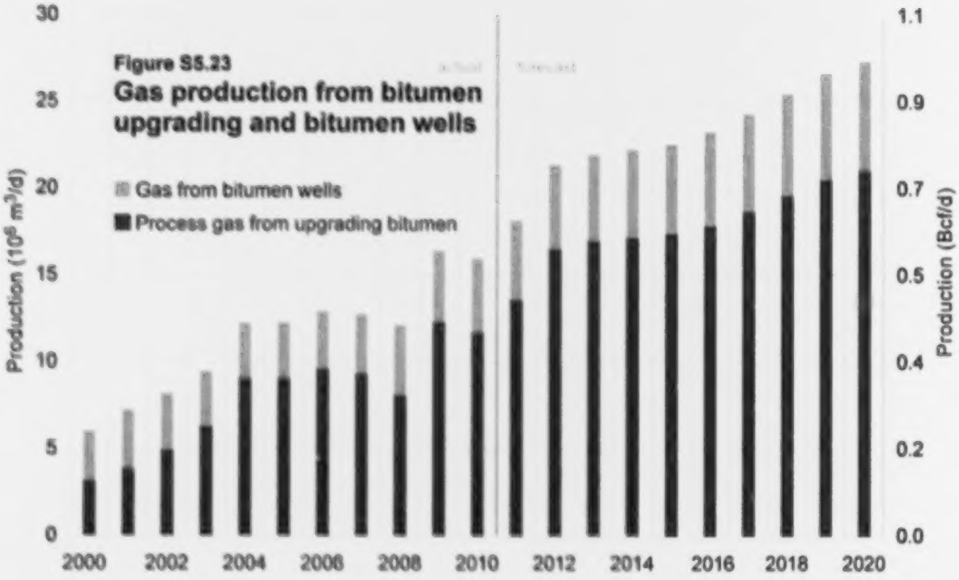


Figure S5.23
Gas production from bitumen upgrading and bitumen wells

In 2010, about 11.7 10^6 m^3/d of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 21.0 10^6 m^3/d by the end of the forecast period. Natural gas production from primary and thermal bitumen wells was 4.3 10^6 m^3/d in 2010 and is forecast to increase to 6.3 10^6 m^3/d by 2020. This gas is used mainly as fuel to create steam for on-site operations. Additional small volumes of gas are produced from primary bitumen wells and are used for local operations.

5.2.6 Supply Costs

The supply cost for a resource or project can be defined as the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, and earn a 10 per cent specified return on investment.

The following table summarizes estimated costs of conventional gas supplies from selected areas in Alberta based on 2009 drilling and operating costs and production rates. Supply costs for different geological plays within the province can vary significantly because of differing discovered reserves and resulting production rates and drilling and operating costs. Some selected results for Alberta are displayed below in **Table 5.16**.

Table 5.16 Supply costs for gas wells in Alberta

Area of Alberta	Resource type	Resource group	Supply cost ($C/GJ)
Central	Tight	Mannville	3.23
West Central	Conventional	Upper Cretaceous; Upper Colorado	3.68
Southwest	Conventional	Middle and Lower Manville	4.45
Kaybob	Conventional	Triassic	4.76
Southern	Conventional	Mannville	5.44
Deep Basin	Tight	Mannville; Jurassic	5.62
CBM deposit play area	Coalbed methane	Mannville	6.31
Southern Foothills	Conventional	Mississipian; Upper Devonian	7.14
Northeast Alberta	Conventional	Manville; Upper Devonian	8.54
Central Foothills	Conventional	Mississippi	9.04
Eastern	Conventional	Colorado; Manville	9.83

Source: National Energy Board (NEB), November 2010. *Supply Costs in Western Canada in 2009.*

5.2.7 Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability; the ERCB does not use these volumes in the long-term production projection. Several pools in the province are being used for commercial natural gas storage to provide an efficient means of balancing supply with fluctuating market demand. Commercial natural gas storage is defined as the storage of third-party non-native gas; it allows marketers to take advantage of seasonal price differences, effect custody transfers, and maintain reliability of supply. Natural gas from many sources may be stored at these facilities under fee-for-service, buy-sell, or other contractual arrangements.

In summer, when demand is lower, natural gas is injected into these pools. As winter approaches, the demand for natural gas rises, injection slows or ends, and storage withdrawals generally begin at high withdrawal rates. Commercial natural gas storage pools, along with the operators and storage information, are listed in **Table 5.17**.

In 2010, natural gas withdrawals for all storage schemes exceeded injections by 277 10^6 m^3. Marketable gas production volumes determined for 2010 were adjusted to account for the imbalance between volumes injected and volumes withdrawn from these storage pools. For the purpose of projecting future natural gas production, the ERCB assumes that injections and withdrawals are balanced for each year during the forecast period.

Table 5.17 Commercial natural gas storage pools as of December 31, 2010

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2010 (10^6 m^3)	Withdrawal volumes, 2010 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	644	861
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	1 552	35 217	1 130	1 070
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	858	995
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	591	721
Hussar Glauconitic R	Husky Oil Operations Limited	423	5 635	199	206
McLeod Cardium A	Iberdrola Canada Energy Services Ltd.	986	16 900	343	287
McLeod Cardium D	Iberdrola Canada Energy Services Ltd.	282	4 230	152	274
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 254	50 713	1 435	1 633
Warwick Glauconitic-Nisku A	Warwick Gas Storage Inc. (WGSI)	881	3 300	434	17
Total				**5 787**	**6 064**
Difference					**277**

Figure S5.24 shows the location of existing gas storage facilities at the Alberta pipeline systems.

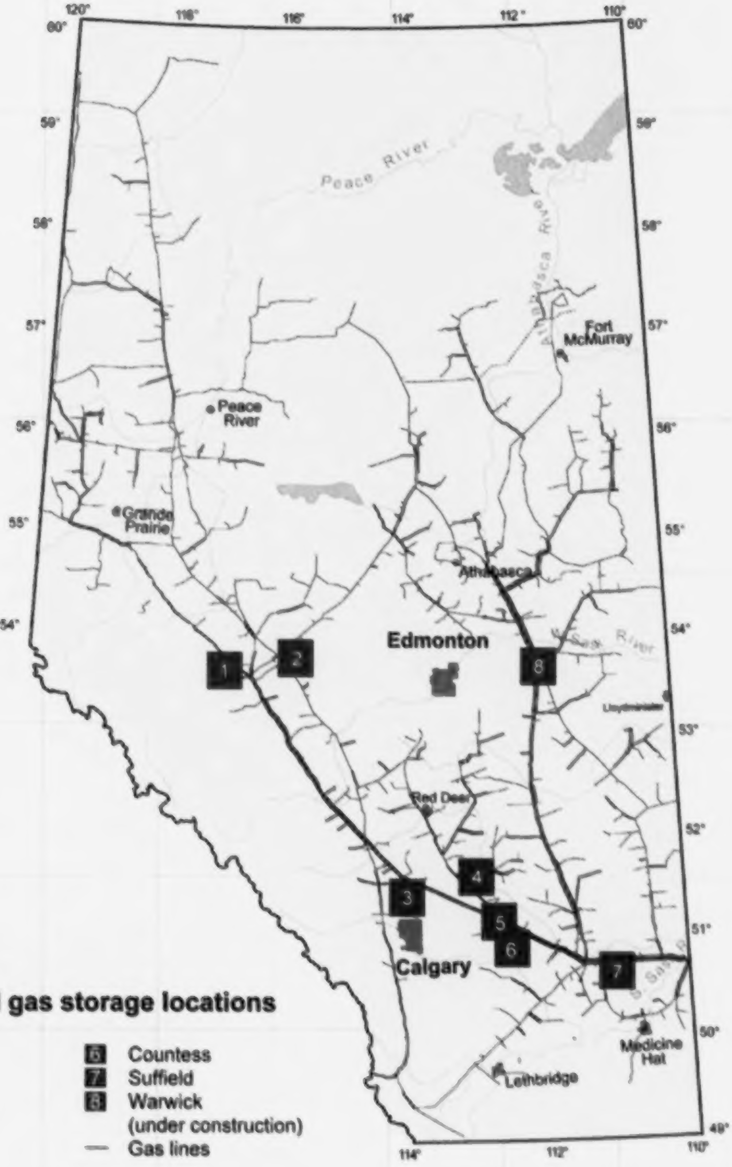

120°
118°
116°
114°
112°
110°
60°
59°
58°
57°
56°
55°
54°
53°
52°
51°
50°
49°
Peace River
Athabasca River
Fort McMurray
Peace River
Grande Prairie
Athabasca
Edmonton
N. Sask. River
Lloydminster
Red Deer
Calgary
S. Sask. R.
Medicine Hat
Lethbridge
1
2
3
4
5
6
7
8
1 Edson
2 McLeod
3 Crossfield
4 Carbon
5 Hussar
6 Countess
7 Suffield
8 Warwick (under construction)
— Gas lines

Figure S5.24
Commercial gas storage locations

5.2.8 Alberta Natural Gas Demand

The Alberta *Gas Resources Preservation Act* (first proclaimed in 1949) provides supply security for consumers in Alberta by "setting aside" large volumes of gas for their use before gas removals from the province are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the ERCB for a permit authorizing the removal. Exports of gas from Alberta are only permitted if the gas to be removed is surplus to the needs of Alberta's core consumers for the next 15 years. Core consumers are defined as Alberta residential, commercial, and institutional gas consumers who do not have alternative sustainable fuel sources.

The calculation in **Table 5.18** is done annually to determine what volume of gas is available for removals from Alberta after accounting for Alberta's future requirements. Using the 2010 remaining established reserves number, surplus natural gas is currently calculated to be 505 10^9 m^3. **Figure S5.25** illustrates historical "available for permitting" volumes.

Table 5.18 Estimate of gas reserves available for inclusion in permits as of December 31, 2010

	10^9 m^3 at 37.4 MJ/m^3
Reserves (as of year-end 2010)	
1. Total remaining established reserves	1 066
Alberta requirements	
2. Core market requirements	114
3. Contracted for non-core markets[a]	131
4. Permit-related fuel and shrinkage	29
Permit requirements	
5. Remaining permit commitments[b]	287
6. Total requirements	561
Available	
7. Available for permits	505

[a] For these estimates, 15 years of core market requirements and 5 years of noncore requirements were used.

[b] The remaining permit commitments are split approximately 90 per cent under short-term permits and 10 per cent under long-term permits.

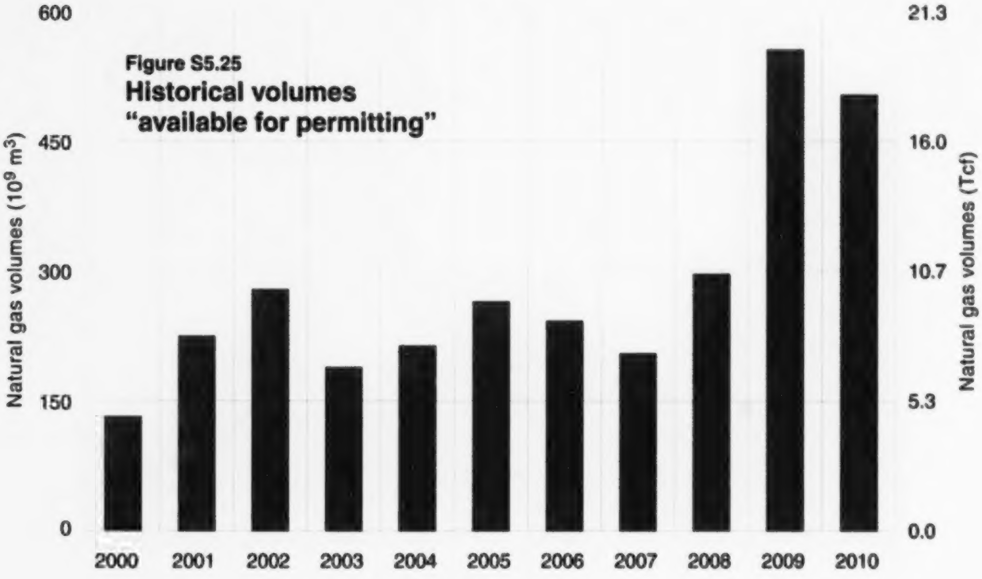


Figure S5.25
Historical volumes "available for permitting"

Gas removals from Alberta have declined since 2001, from 315.5 10^6 m^3/d in 2001 to 196.5 10^6 m^3/d in 2010. Based on the ERCB's projection of gas production, this rate is forecast to drop to 50.8 10^6 m^3/d by 2020.

The ERCB annually reviews the projected demand for Alberta natural gas. It focuses these reviews on intra-Alberta natural gas use and provides a detailed analysis of many factors, such as population growth, industrial activity, alternative energy sources, and other factors that influence natural gas consumption in the province.

Forecasting demand for Alberta natural gas in markets outside the province is done less rigorously. For Canadian ex-Alberta markets, historical demand growth and forecast supply are used in developing the demand forecasts. Export markets are forecast based on export pipeline capacity available to serve such markets, and on the recent historical trends in meeting that demand. Excess pipeline capacity to the U.S. allows gas to move to areas of the U.S. that provide for the highest netback to the producer. The major natural gas pipelines in Canada that move Alberta gas to market are illustrated in **Figure S5.26**, with removal points identified.

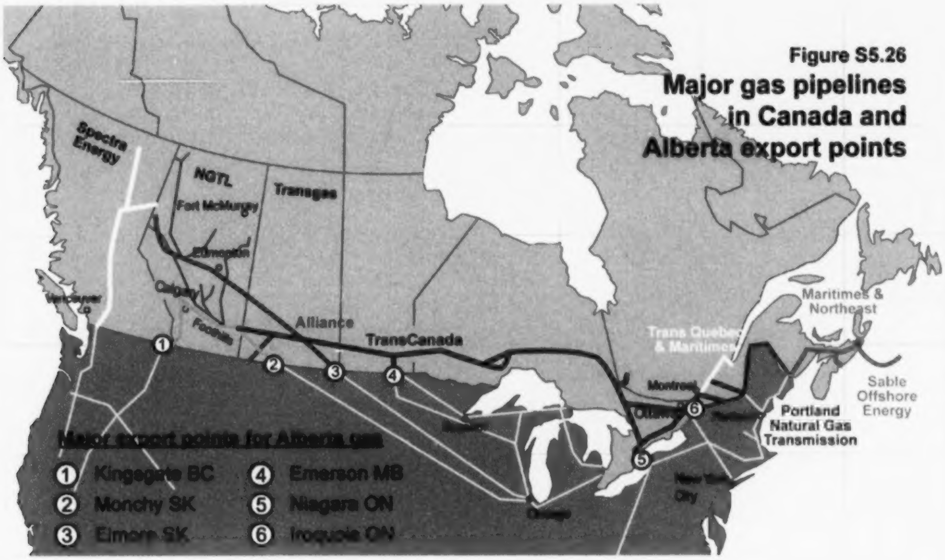


Figure S5.26
Major gas pipelines in Canada and Alberta export points

Spectra Energy
NGTL
Transgas
Fort McMurray
Edmonton
Calgary
Vancouver
Foothills
Alliance
TransCanada
Montreal
Ottawa
Trans Quebec & Maritimes
Maritimes & Northeast
Sable Offshore Energy
Portland Natural Gas Transmission
New York City
Chicago
① ② ③ ④ ⑤ ⑥
Major export points for Alberta gas
① Kingsgate BC
② Monchy SK
③ Elmore SK
④ Emerson MB
⑤ Niagara ON
⑥ Iroquois ON

Figure S5.27 illustrates the breakdown of marketable natural gas demand in Alberta by sector. In 2010, demand within Alberta was 122.1 10^6 m^3/d, which represented 38 per cent of the total Alberta natural gas production. By the end of the forecast period, demand is estimated to reach 166.4 10^6 m^3/d, or 77 per cent of total production.

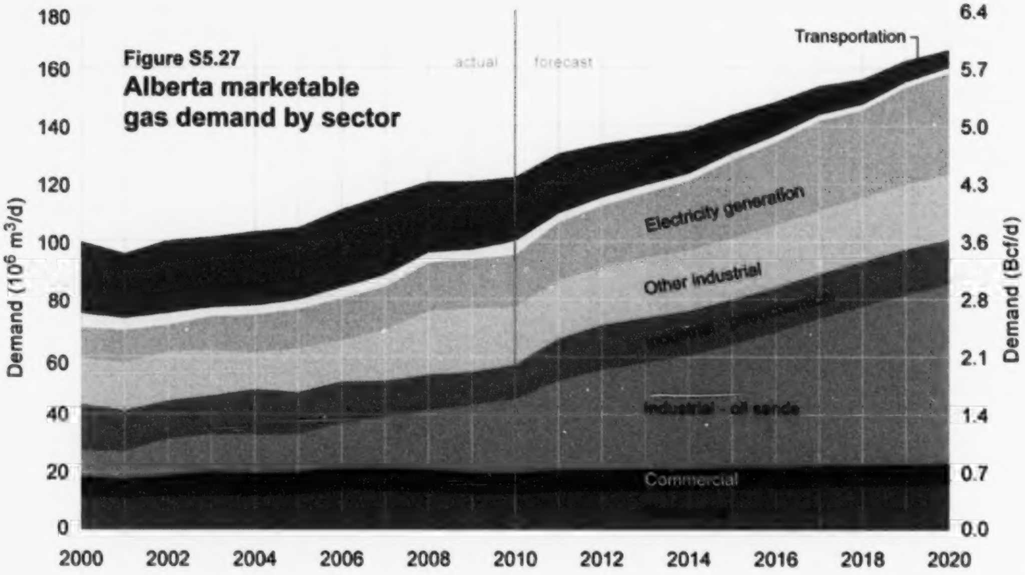


Figure S5.27
Alberta marketable gas demand by sector

Residential gas requirements are expected to grow moderately at an average annual rate of 2 per cent over the forecast period. The key variables that affect residential gas demand are natural gas prices, population, the number of households, energy efficiencies, and the weather. Energy efficiency improvements prevent household energy use from rising significantly.

Commercial gas demand in Alberta has declined gradually since 2003 and is expected to continue to decline at an average annual rate of 0.5 per cent per year over the forecast period. This is largely due to gains in energy efficiencies and a shift towards electricity.

The electricity generating industry will require increased volumes of natural gas to fuel the new industrial on-site and peaking plants expected to come on stream over the forecast period. Natural gas requirements for electricity generation are expected to increase from about 18.3 10^6 m^3/d in 2010 to 35.1 10^6 m^3/d by 2020. The projected increase in gas demand in this sector is due to the assumption that gas will be the preferred feedstock for new power plants. See Section 9 for details on the new gas-fired plants projected to come on stream over the forecast period.

Another significant increase in Alberta demand is due to projected development in the industrial sector. Gas demand for oil sands operations will increase from 25.1 10^6 m^3/d in 2010 to 62.0 10^6 m^3/d by 2020. The purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil (SCO), including gas used by the electricity cogeneration units on site at the oil sands operations, shown in **Figure S5.28**, are expected to increase from 35.8 10^6 m^3/d in 2010 to 83.4 10^6 m^3/d by 2020. All purchased gas use for upgrading operations, including the gas used by Nexen/OPTI to upgrade in situ bitumen, is included in the mining and upgrading category shown in the Figure. **Table 5.19** outlines the average purchased gas use rates for oil sands operations.

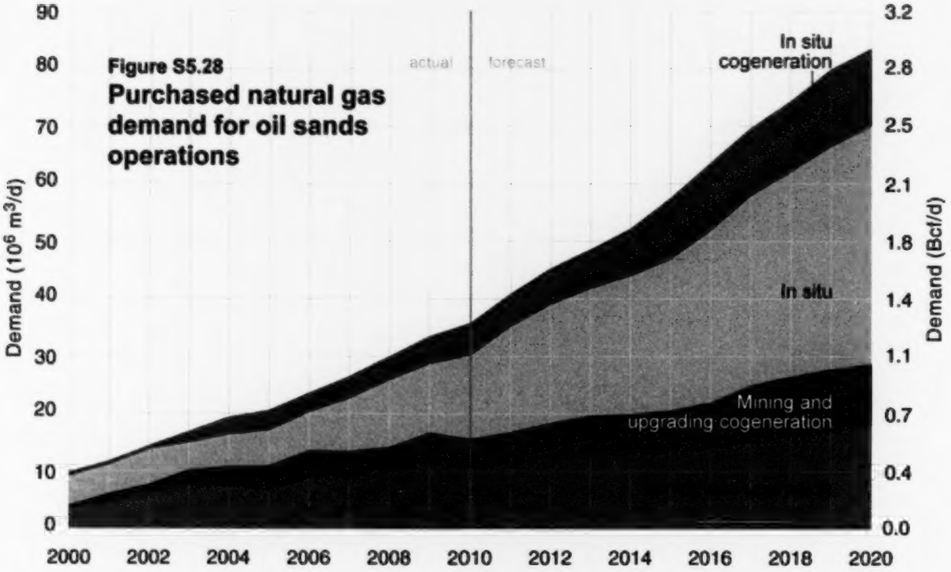


Figure S5.28
Purchased natural gas demand for oil sands operations

Table 5.19 2010 oil sands average purchased gas use rates*

	Excluding purchased gas for cogeneration		Including purchased gas for cogeneration	
Extraction method	**(m^3/m^3)**	**(mcf/bbl)**	**(m^3/m^3)**	**(mcf/bbl)**
In situ				
SAGD	167	0.94	241	1.36
CSS	189	1.06	237	1.33
Mining with upgrading	83	0.47	124	0.70

* Expressed as cubic metres of natural gas per cubic metre of bitumen/synthetic crude oil production. Rates are an average of typical schemes with sustained production.

As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. **Figure S5.29** illustrates the sector's total gas demand, which is the sum of purchased gas, process gas, and solution gas produced at bitumen wells. This demand is expected to nearly double from 41.1 10^6 m^3/d in 2010 to 86.6 10^6 m^3/d by 2020.

Gas use by the oil sands sector, including gas used by the electricity cogeneration units on site at the oil sands operations, as shown in **Figure S5.30**, was 55.3 10^6 m^3/d in 2010 and is forecast to increase to 114.2 10^6 m^3/d by 2020.

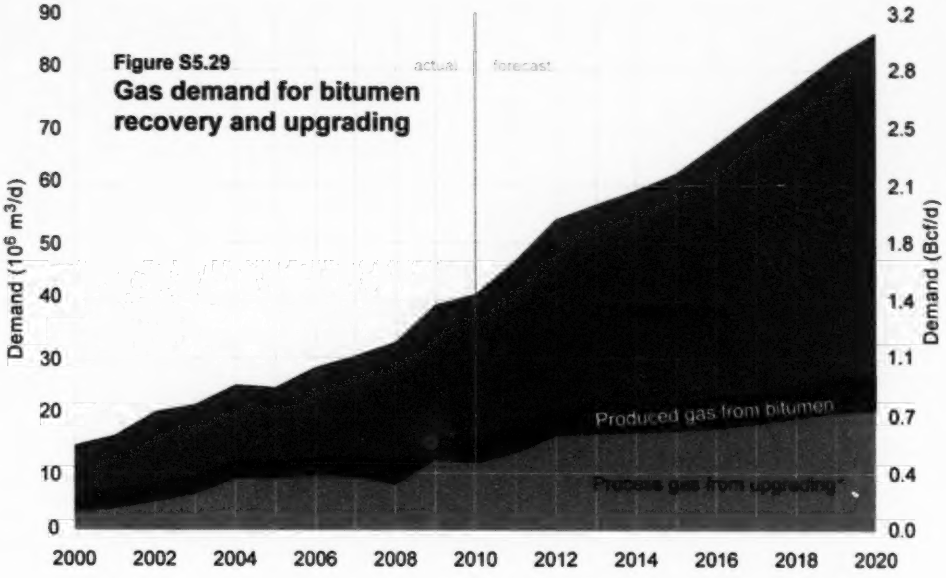


Figure S5.29
Gas demand for bitumen recovery and upgrading

* Does not include process gas used for electricity generation.

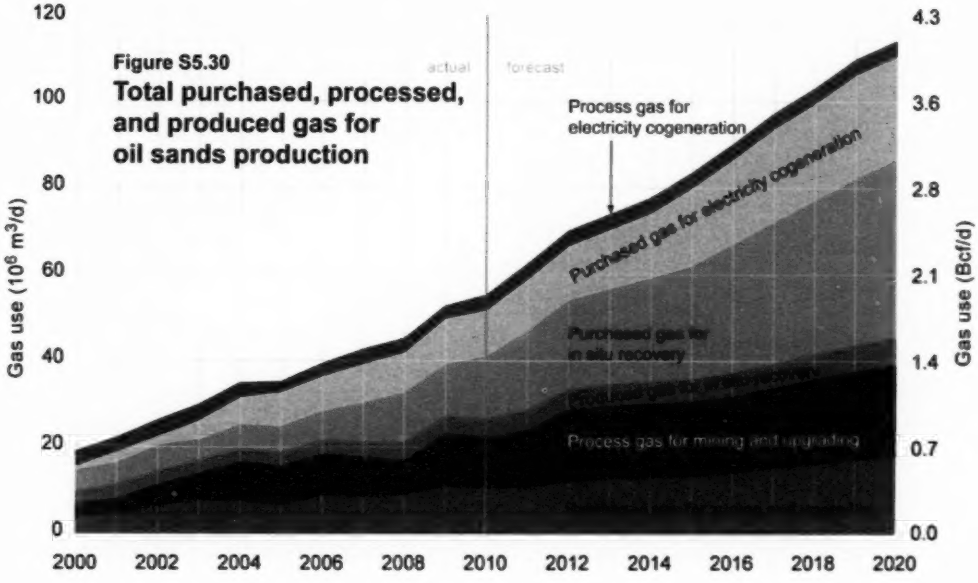
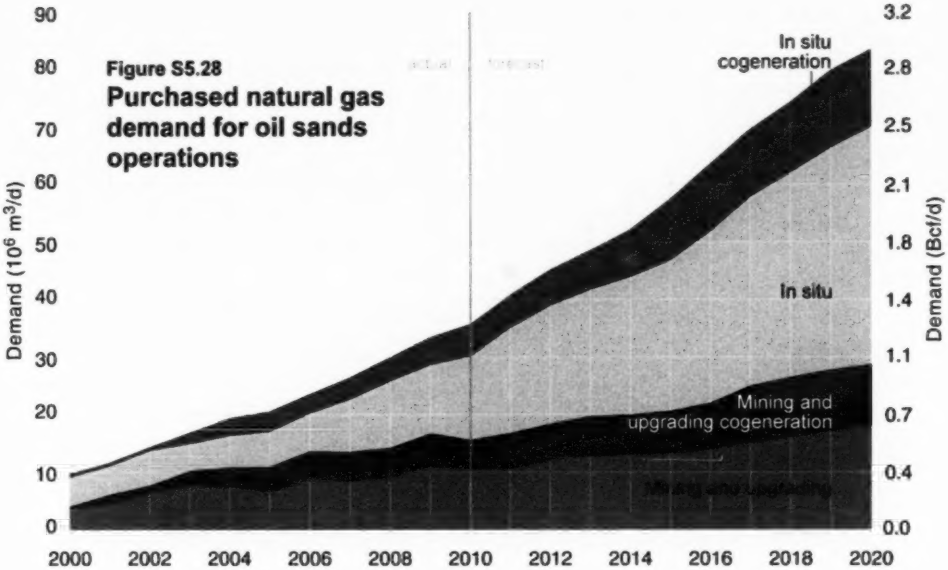


Figure S5.30
Total purchased, processed, and produced gas for oil sands production

The potential high use of natural gas in bitumen production and upgrading has exposed the companies involved in the business to risk caused by volatile gas prices. The Nexen/OPTI Long Lake Project began commercial operations in January 2009, employing technology that produces synthetic gas by burning ashphaltines in its new bitumen upgrader. In previous years when the price of natural gas was relatively bitumen, is included in the mining and upgrading category shown in the Figure. **Table 5.19** outlines the average purchased gas use rates for oil sands operations.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Purchased natural gas demand for oil sands operations

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CSS	189	1.06	237	1.33
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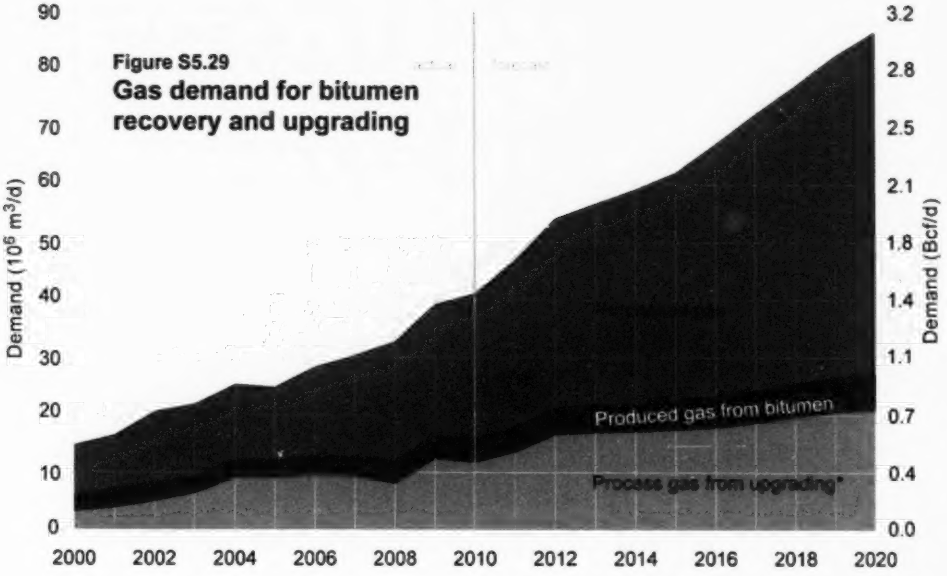

Figure S5.29
Gas demand for bitumen recovery and upgrading

* Does not include process gas used for electricity generation.

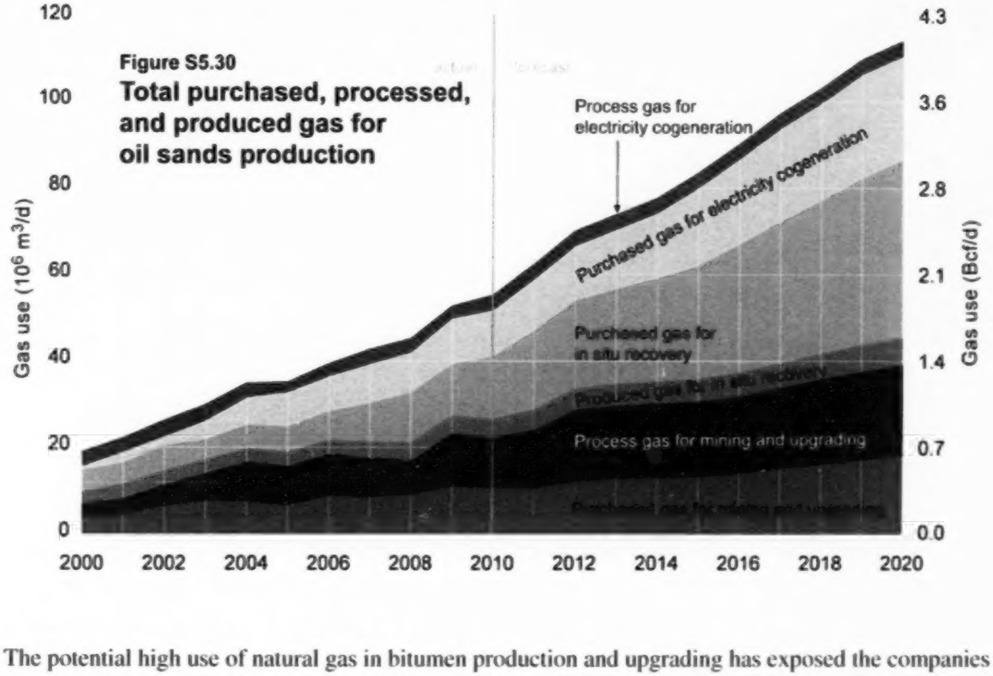

Figure S5.30
Total purchased, processed, and produced gas for oil sands production

The potential high use of natural gas in bitumen production and upgrading has exposed the companies involved in the business to risk caused by volatile gas prices. The Nexen/OPTI Long Lake Project began commercial operations in January 2009, employing technology that produces synthetic gas by burning ashphaltines in its new bitumen upgrader. In previous years when the price of natural gas was relatively high, companies were exploring the option of self-sufficiency for their gas requirements. The existing bitumen gasification technology was one attractive alternative being pursued. If gas prices increase to levels at which gasification at upgrading operations is again considered economic, natural gas requirements could decrease substantially.

Figure S5.31 shows total Alberta natural gas demand and production. Natural gas produced from bitumen wells or from bitumen upgrading (**Figure S5.27**) is considered to be used on site and is not included as marketable production available to meet Alberta demand. Therefore, gas removals from the province represent natural gas production from conventional and CBM only, minus Alberta demand.

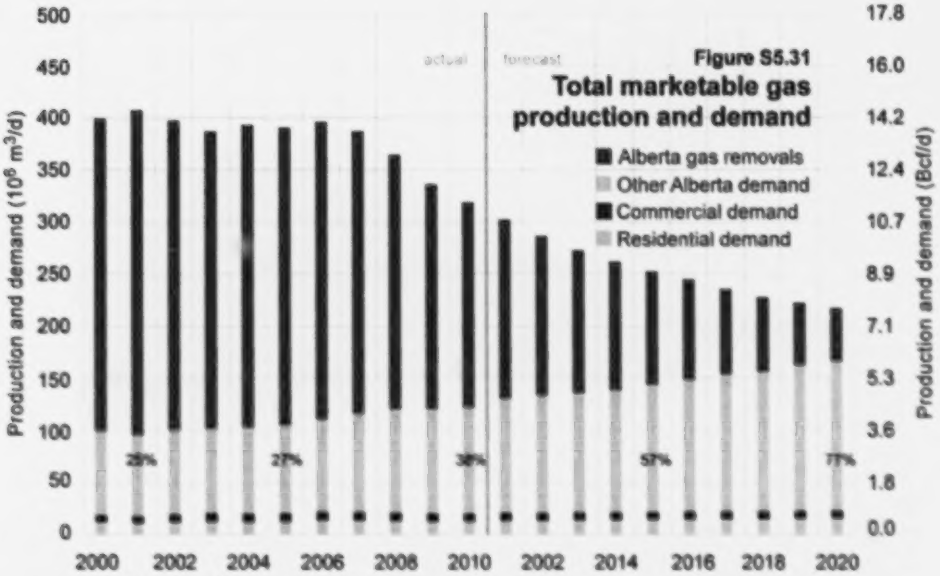

Figure S5.31
Total marketable gas production and demand

2010 volumes for shale gas production is included in the chart; shale gas production has not been forecast

In 2010, about 38 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the U.S. By the end of the forecast period, domestic demand will represent 77 per cent of total natural gas production.

HIGHLIGHTS

Total remaining extractable NGL reserves have decreased by 4 per cent from 2009 as a result of decreasing natural gas reserves.

Approximately 63 per cent of total ethane in the gas stream was extracted in 2010, compared with 56 per cent in 2009.

Of the total ethane extracted, straddle plants recovered 73 per cent and the remaining was removed at field and fractionation plants.

The decline in the production of propane, butanes, and pentanes plus moderated in 2010 due to increased production of liquids rich natural gas in 2010.

6 // NATURAL GAS LIQUIDS

Produced natural gas is primarily methane, but it also contains heavier hydrocarbons consisting of ethane (C_2), propane (C_3), butanes (C_4), and pentanes and heavier hydrocarbons (typically referred to as pentanes plus or C_5+), all of which are referred to as natural gas liquids (NGLs). Natural gas also contains water and contaminants such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S). In Alberta, the production of all ethane, pentanes plus, and most propane and butanes are from the raw natural gas stream. Most of the NGL supply is recovered from the processing of natural gas at gas plants, although some pentanes plus is recovered as condensate at the field level and sold as product. Other sources of NGL are crude oil refineries, where small volumes of propane and butanes are recovered, and gases produced as by-products of bitumen upgrading called off-gas. Off-gases are a mixture of hydrogen and light gases, including ethane, propane, and butanes. Most of the off-gases produced from oil sands upgraders are currently being used as fuel for oil sands operations. Unconventional gas is generally lean, with fewer hydrocarbon liquids, so it is not expected to contribute to future NGL reserves.

The ERCB estimates remaining reserves of NGLs based on volumes expected to be recovered from remaining raw natural gas using existing technology and projected market conditions, which are described in Section 6.2.1. Initial reserves for NGLs are not calculated, since historically only a fraction of the liquid volume that could have been extracted was recovered and much was flared for lack of market demand. The ERCB's projections for the overall recovery of each NGL component are explained in Section 5.1.3.6. As shown graphically in **Figure R5.7**, the estimate of the reserves of liquid ethane is based on the assumption that 65 per cent of the total raw ethane gas reserves will be extracted from the natural gas stream, while 85 per cent of propane, 90 per cent of butane, and 100 per cent of pentanes plus are assumed extracted from the gas stream. Although it is reasonable to expect that some heavier liquids will drop out in the reservoir as pressure declines with depletion and will not be recovered, the ERCB's calculations assume that the composition of raw produced gas remains unchanged over the life of a pool because it is difficult to predict and the volume is not expected to be significant. The liquids reserves expected to be removed from natural gas are referred to as extractable reserves, and those not expected to be recovered are included as part of the province's natural gas reserves, as discussed in Section 5.1.

6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2010 are summarized in **Tables 6.1** and **6.2**. **Figure R6.1** shows remaining established reserves of extractable NGLs compared with 2010 production.

Total remaining reserves of extractable NGLs have decreased by 3.7 per cent compared with 2009 because of the decline in natural gas reserves. Fields that have contributed significantly to this decrease are Brazeau River, Caroline, Cecilia, Kakwa, and Wayne-Rosedale. These fields and others containing large NGL volumes are listed in **Appendix B**, **Tables B.7** and **B.8**.

Table 6.1 Established reserves and production change highlights of extractable NGLs (10^6 m^3 liquid)

	2010	2009	Change
Cumulative net production			
Ethane	292.6	280.1	+12.5
Propane	287.2	279.3	+7.9
Butanes	164.0	159.6	+4.4
Pentanes plus	352.4	345.0	+7.4
Total	**1 096.2**	**1 064.0**	**+32.2**
Remaining (expected to be extracted)			
Ethane	113.2	117.0	-3.8
Propane	64.0	66.1	-2.1
Butanes	35.4	36.7	-1.3
Pentanes plus	48.7	51.6	-2.9
Total	**261.3**	**271.4**	**-10.1**
Annual production	**32.2**	**33.4**	**-1.2**

6.1.2 Ethane

As of December 31, 2010, the ERCB estimates remaining established reserves of extractable ethane to be 113.2 million cubic metres (10^6 m^3) in liquefied form. Of that, 44.3 10^6 m^3 is expected to be recovered from field plants and 68.9 10^6 m^3 from straddle plants that deliver gas outside the province, as shown in **Table 6.2.** It is estimated that 3.1 10^6 m^3 is recoverable from the ethane component of solvent injected

Table 6.2 Reserves of NGLs as of December 31, 2010 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total NGLs in remaining raw gas	173.4	75.2	39.4	48.7	336.8
Liquids expected to remain in dry marketable gas	60.3	11.3	3.9	0	75.5
Remaining established reserves recoverable from					
Field plants	44.3	37.6	23.6	43.8	149.4
Straddle plants	68.9	26.3	11.8	4.9	111.9
Total	**113.2**	**64.0**	**35.4**	**48.7**	**261.3**

into pools under miscible flood to enhance oil recovery. At the end of 2010, only five pools were still actively injecting solvent, the largest being the Judy Creek Beaverhill Lake A, Rainbow Keg River B, and Rainbow Keg River F pools.

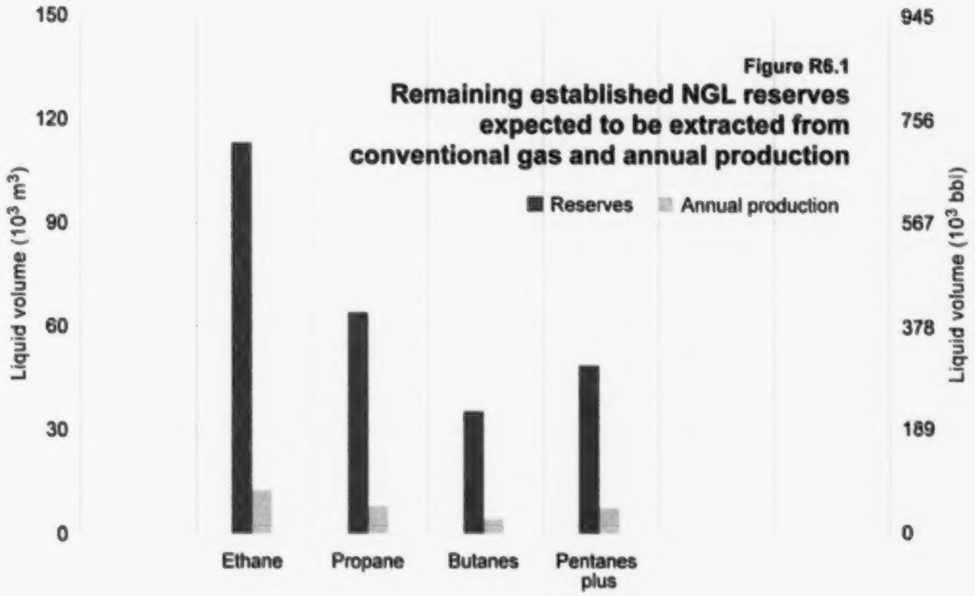

Figure R6.1
Remaining established NGL reserves expected to be extracted from conventional gas and annual production

Thirty-five per cent of the total raw ethane, or 60.3 10^6 m^3 (liquid), is estimated to remain in the marketable gas stream and could potentially be recovered. **Figure R6.2** shows the remaining established reserves of ethane declining rapidly from 1996 to 2003, then levelling off thereafter as more ethane is extracted from raw gas. In 2010, the extraction of specification ethane was 12.5 10^6 m^3, compared with 12.8 10^6 m^3 in 2009.

For individual gas pools, the ethane content of gas in Alberta varies considerably, falling within the range of 0.0025 to 0.20 mole per mole (mol/mol). As shown in **Appendix B**, **Table B.7**, the volume-weighted average ethane content of all remaining raw gas is 0.052 mol/mol. Also listed in this table are ethane volumes recoverable from fields containing the largest ethane reserves. Of these fields, the nine largest—Ansell, Elmworth, Ferrier, Kaybob South, Pembina, Wapiti, Wild River, and Willesden Green—account for 25 per cent of total ethane reserves but only 15 per cent of remaining established marketable gas reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2010, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 64.0 10^6 m^3, 35.4 10^6 m^3, and 48.7 10^6 m^3, respectively. The breakdown in the liquids reserves at year-end 2010 is shown in **Table 6.2**. **Table B.8** in **Appendix B** lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The largest of these fields—Ansell, Brazeau River, Caroline, Elmworth, Ferrier, Kaybob South, Pembina, Wild River, and Willesden Green—account for about 26 per cent of the total propane, butanes, and pentanes plus liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table.

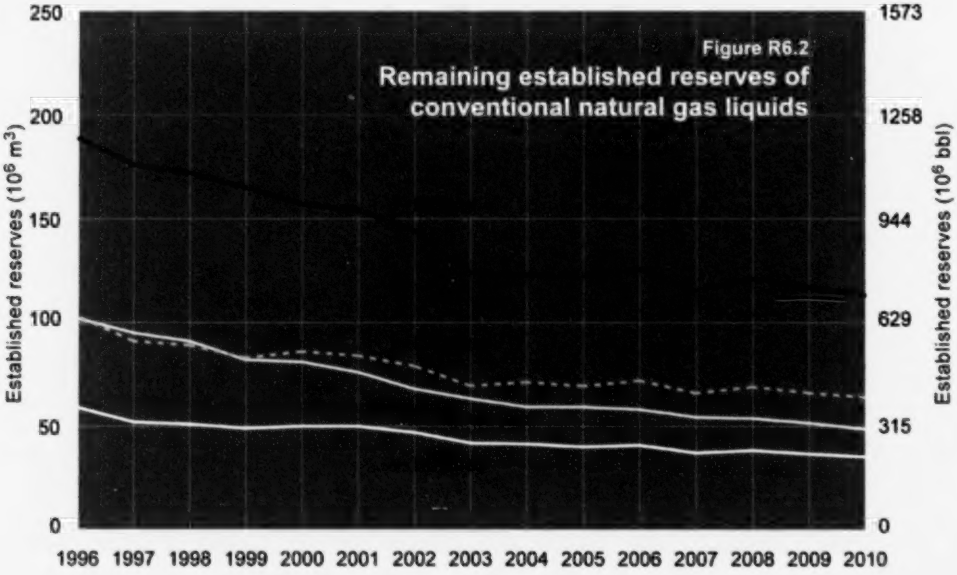
Figure R6.2
Remaining established reserves of conventional natural gas liquids

6.1.4 Ultimate Potential

The remaining ultimate potential of liquid ethane is determined based on the volumes that could be recovered as liquid from the remaining ultimate potential of natural gas, using existing cryogenic technology and projected market demand. The percentage of ethane volumes that have been extracted have been increasing over time. In 2010 there was a significant increase to 63 per cent recovered from 56 percent in 2009. The ERCB estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on a remaining ultimate potential of ethane gas of 127 billion (10^9) m^3, the ERCB estimates the remaining ultimate potential of liquid ethane to be 317 10^6 m^3. The other 30 per cent, or 38 10^9 m^3, of ethane gas is expected to be sold for its heating value as marketable natural gas.

For liquid propane, butanes, and pentanes plus combined, the remaining ultimate potential is 333 10^6 m^3. This assumes that the remaining ultimate potential as a percentage of the initial ultimate potential is similar to that of conventional marketable gas—about 33 per cent.

reserves at year-end 2010 is shown in **Table 6.2**. **Table B.8** in **Appendix B** lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The largest of these fields—Ansell, Brazeau River, Caroline, Elmworth, Ferrier, Kaybob South, Pembina, Wild River, and Willesden Green—account for about 26 per cent of the total propane, butanes, and pentanes plus liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table.

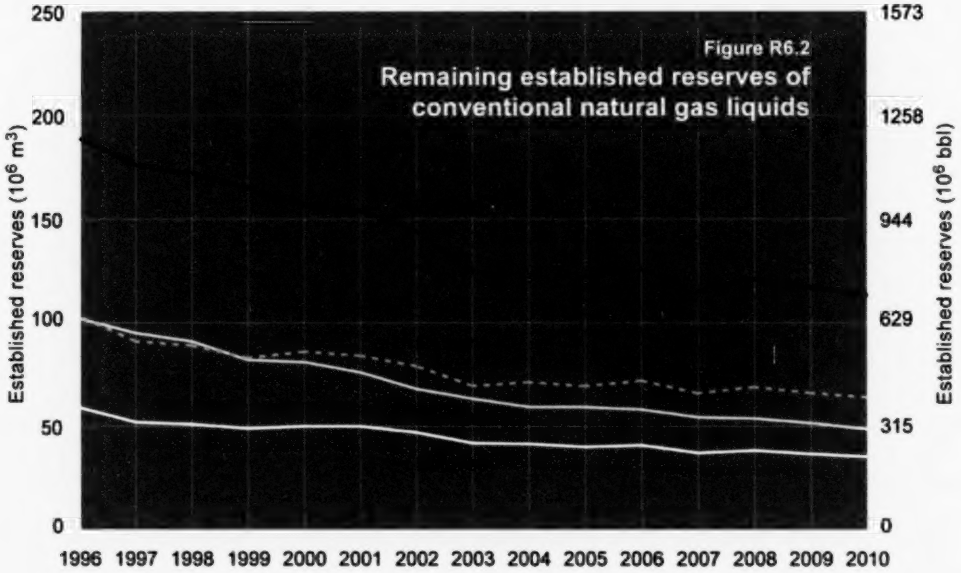
Figure R6.2
Remaining established reserves of conventional natural gas liquids

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6.2 Supply of and Demand for Natural Gas Liquids

For the purpose of forecasting ethane and other NGLs, the NGL content, gas plant recovery efficiencies, NGL prices, and gas production volumes from remaining established reserves and future gas reserves additions affect future production. For ethane, demand also plays a major role in future extraction. The NGL content of new gas reserves is expected to be slightly more liquids rich than existing reserves. In the future, ethane and other gas liquids extracted from oil sands off-gas will supplement supplies from conventional gas production and will be needed to meet the forecast ethane demand.

Ethane and other NGLs are recovered mainly from the processing of natural gas. Field gas processing facilities ensure that natural gas meets the quality specifications of the rate-regulated natural gas pipeline systems, which may require removal of NGLs to meet pipeline hydrocarbon dew point specifications. Removal of other contaminants such as H_2S and CO_2 is also required. The field plants generally recover additional volumes of NGLs—more than what is required to meet pipeline specifications, depending on the plant's extraction capability—to obtain full value for the NGL components. Generally, the heavier hydrocarbon constituents (butanes and pentanes plus) are removed at field plants.

Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated into specification products. These NGL processing facilities realize economies of scale by fractionating NGL mix streams received from many gas plants.

Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually located on rate-regulated main gas transmission pipelines at border delivery points. Straddle plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery determined by the plant's extraction capability, contractual arrangements, and product demand. **Figure S6.1** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

6.2.1 Ethane and Other Natural Gas Liquids Production—2010

In Alberta, there are about 550 active gas processing plants that recover NGL mix or specification products, 10 processing plants that fractionate NGL mix streams into specification products, and 9 straddle plants. The Harmattan-Elkton gas plant was approved by the ERCB in December 2010 as a co-streaming operation that allows the plant to reprocess marketable gas from the NOVA Gas Transmission Ltd. Western Alberta System. It is also a field plant for the processing of raw gas from nearby pools. The approval allows the Harmatton-Elkton plant to divert up to 13.89 10^6 cubic metres per day (m^3/d) to the plant for reprocessing and recovery of ethane and other NGLs.

Recovery efficiencies of NGL specification products at field plants depend on plant design and economics and generally range from 75 to 98 per cent for propane, 90 to 100 per cent for butanes, and 98 to 100 per cent for pentanes plus. A few field plants are also capable of extracting ethane as a specification product or as an ethane plus (C_2+) mix, and as a result are referred to as deep cut facilities.

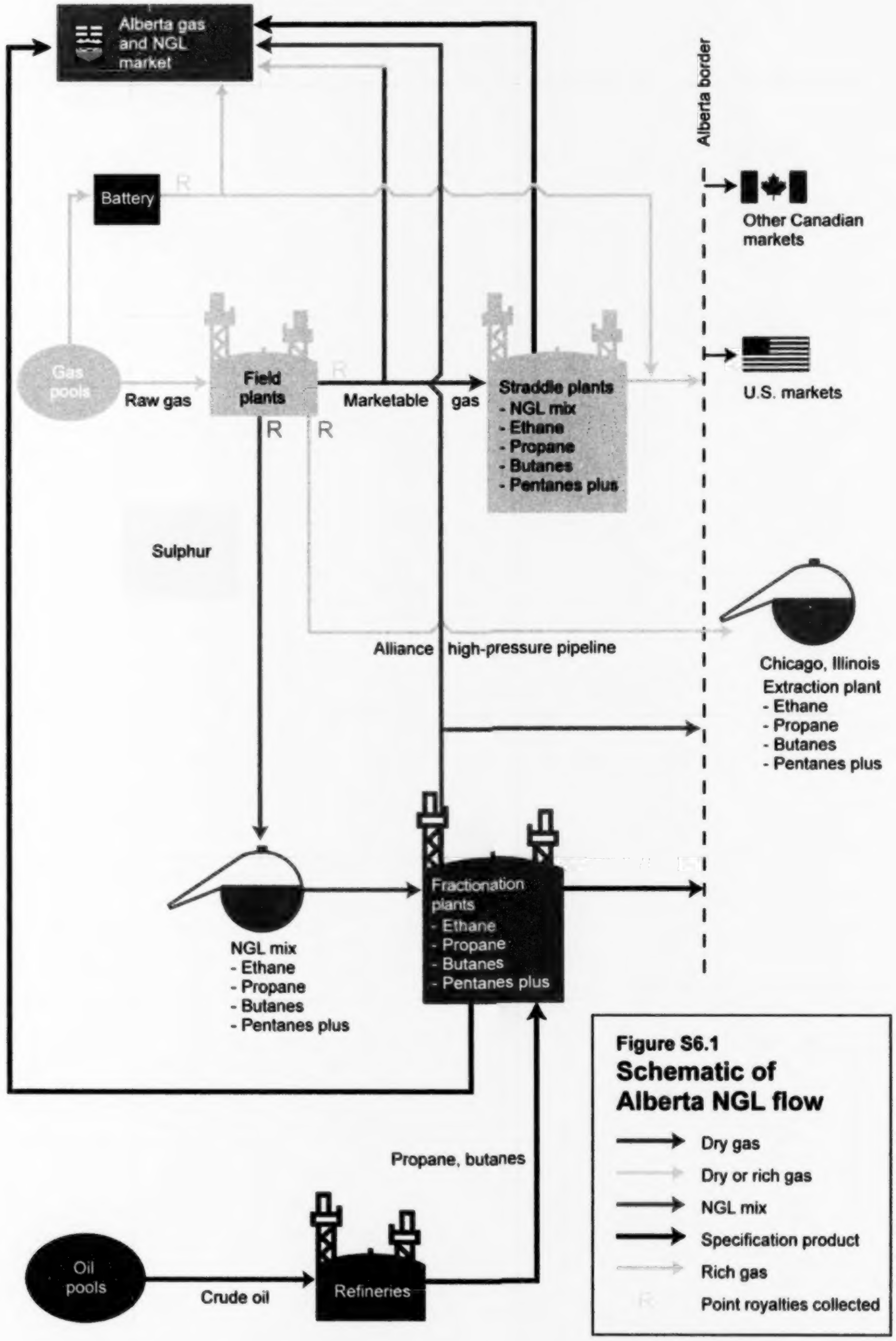

Alberta gas and NGL market
Alberta border
Battery
R
Other Canadian markets
Gas pools
Raw gas
Field plants
R
Marketable gas
Straddle plants
- NGL mix
- Ethane
- Propane
- Butanes
- Pentanes plus
U.S. markets
R
R
Sulphur
Alliance high-pressure pipeline
Chicago, Illinois
Extraction plant
- Ethane
- Propane
- Butanes
- Pentanes plus
NGL mix
- Ethane
- Propane
- Butanes
- Pentanes plus
Fractionation plants
- Ethane
- Propane
- Butanes
- Pentanes plus
Propane, butanes
Oil pools
Crude oil
Refineries
Dry gas
Dry or rich gas
NGL mix
Specification product
Rich gas
R
Point royalties collected

Figure S6.1
Schematic of Alberta NGL flow

Ethane recovery at straddle plants varies from 40 to 90 per cent and averages 65 per cent. The average percentages of propane, butanes, and pentanes plus recovered at Alberta straddle plants are 98.5, 99.5, and 99.8, respectively. **Table 6.3** outlines information about the straddle plants operating in Alberta in 2010, including the plant location, operator name, approved natural gas throughput volumes, 2010 natural gas receipts (actual throughput volumes), and the volumes of ethane recovered in 2010.

Table 6.3 Straddle plants in Alberta, 2010

Area of straddle plant	Location	Operator	2010 gas approved volumes (10^3 m^3/d)	2010 gas receipts (10^3 m^3/d)	2010 ethane production (m^3/d)
Empress	10-11-020-01W4M	Spectra Energy Empress Management	67 960	45 618	4 033
Empress	04-12-020-01W4M	BP Canada Energy Company	176 750	51 511	5 917
Cochrane	16-16-026-04W5M	Inter Pipeline Extraction Ltd.	70 450	51 648	7 844
Ellerslie (Edmonton)	04-04-052-24W4M	AltaGas Ltd.	11 000	8 134	1 715
Empress	01-10-020-01W4M	ATCO Midstream Ltd.	31 000	11 580	709
Fort Saskatchewan*	01-03-055-22W4M	ATCO Midstream Ltd.	1 051	775	0
Empress	16-02-020-01W4M	1195714 Alberta Ltd.	33 809	31 813	4 010
Joffre (JEEP)	03-29-038-25W4M	Taylor Management Company Inc.	7 066	288	728
Atim* (Villeneuve)	08-05-054-26W4M	ATCO Midstream Ltd.	1 133	1 029	0
Total			**400 219**	**202 396**	**24 956**

* These plants are approved to recover a C_2+ mix and not specification ethane.

In 2010, ethane volumes extracted at Alberta processing facilities decreased marginally to 34.2 thousand (10^3) m^3/d from 35.1 10^3 m^3/d in 2009. About 63 per cent of total ethane in the gas stream was extracted in 2010, compared with 56 per cent in 2009, while the remainder was left in the gas stream and sold for its heating value. **Table 6.4** shows the volumes of specification ethane extracted at the three types of processing facilities during 2010.

The C_3+ mix of NGLs shipped from the Taylor gas plant in British Columbia to the Redwater fractionation plant for fractionation into specification products is included in Alberta production volumes.

Table 6.4 Ethane extraction volumes at gas plants in Alberta, 2010

Gas plants	Volume (10^3 m^3/d)	Percentage of total
Field plants	2.4	7
Fractionation plants	6.8	20
Straddle plants	25.0	73
Total	**34.2**	**100**

Table 6.5 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2010.

Despite weak levels of natural gas drilling and new well connections, the decline in the production of propane, butanes, and pentanes plus in Alberta appears to be slowing down as a result of the increased focus by industry on developing liquids rich gas pools. Propane, butanes, and pentanes plus production declined by 5.6 per cent, 3.1 per cent, and 3.5 per cent respectively, in 2010 over 2009. This compares to the decline rates in 2009 of 6.4 per cent, 8.8 per cent, and 6.0 per cent, respectively.

As a result of low natural gas prices, industry is focusing its attention on developing liquids rich gas pools because the prices of NGLs (with the exception of ethane) track the price for crude oil.

In 2010, PSAC Area 2 (Foothills Front) experienced a 10 per cent increase in the number of new gas well connections. This area has the largest remaining extractable liquid reserves in the province. PSAC Area 3 (Southeastern Alberta), known for its dry gas production, experienced a 10 per cent decrease in new well connections. The shift by industry to develop pools with gas liquids is expected to continue, which will result in higher gas liquids production than previously forecast.

Ratios of liquid production to marketable conventional gas for 2010 and 2020 are shown in **Table 6.5**. Small volumes of propane and butanes production from oil sands off-gas is included in the production volumes.

In 2010, propane and butane volumes recovered at crude oil refineries were 0.6 10^3 m^3/d and 1.7 10^3 m^3/d, respectively.

Table 6.5 Liquid production at ethane extraction plants in Alberta, 2010 and 2020[a]

	2010		2020	
Gas liquid	Daily production (10^3 m^3/d)	Liquid/gas ratio (m^3/10^6 m^3)	Daily production (10^3 m^3/d)	Liquid/gas ratio (m^3/10^6 m^3)
Ethane	34.2	116	34.2	186
Propane	21.7	74	15.5	82
Butanes	12.0	41	8.9	47
Pentanes plus	20.3	69	14.4	76

[a] Ratios of liquid production are in m^3 liquid per 10^6 m^3 marketable conventional gas production.

6.2.2 Ethane and Other Natural Gas Liquids—Recent Developments

As conventional gas production declines, less ethane from this source will be available for use by the petrochemical sector. In response to the tight ethane supply and demand balance in Alberta, the provincial government implemented the Incremental Ethane Extraction Program (IEEP) in September 2006 and amended and extended the program in March 2011. The program, initially designed to encourage extraction of ethane from natural gas, has been revised to also encourage ethane extraction from off-gases that result from bitumen upgrading or refining. Alberta's petrochemical industry is the largest in Canada and depends on the availability of competitively priced ethane to remain viable. The sector adds value to the economy with annual deliveries of almost $9.2 billion and exports of more than $5.4 billion in 2009 (latest numbers available). The capture of ethane from oil sands off-gases will provide an additional source of ethane feedstock. Most off-gas is currently consumed as fuel in oil sands operations.

IEEP has been extended for five years with about $310 million of the original $350 million dollars still available to be used. Fractionation credits are provided to petrochemical companies that consume incremental ethane for value-added upgrading, in Alberta, to ethylene and derivatives. The credit value for ethane or ethylene from natural gas remains unchanged at $1.80 per barrel (bbl). The government program recognizes that off-gas capture from bitumen upgrading or refining including ethane or ethylene is considerably more capital intensive than conventional-sourced ethane, and as a result provides a credit value for off-gas ethane of $5.00/bbl. The credit is owned by the company that consumes the ethane or ethylene and can be sold to either a natural gas or a bitumen royalty payer to be applied against its royalty obligation.

The two projects currently operating under IEEP are described in **Table 6.6**. The two applications the government has received for the 2010 application season are also described in **Table 6.6.**

Table 6.6 IEEP 2010 applications and currently operational projects

	Applicant	Incremental ethane volumes (m^3/d)
Applications		
Hidden Lake Streaming Project (start-up date: Q 3/4, 2011)	NOVA Chemicals Corporation	205
Williams Off-gas Extraction Project (start-up date: Q4, 2012)	NOVA Chemicals Corporation	1 580
Operational projects		
Rimbey Ethane Extraction Project	Dow Chemical Canada Inc.	795
Empress V Expansion Deep Cut Project	Dow Chemical Canada Inc.	1 100

There is currently only one project in operation that extracts NGLs from oil sands off-gas in the province. Williams Companies Inc. (Williams) extracts a C_3+ and olefins mix from a small portion of the off-gas produced at Suncor's upgrading facility in the Fort McMurray area and sends the liquid mix to the Redwater fractionation plant near Edmonton for further processing into products. The off-gas is transported to the Williams extraction plant in the Suncor Oil Sands Pipeline. Production from the Williams facility was 1718 m^3/d in 2010.

Williams received approval in June 2010 to build a new pipeline to transport 6795 m^3/d of off-gas liquids from its extraction facility to its fractionation plant for the removal of ethane and other NGLs and olefins. This 12-inch proposed Williams Boreal Pipeline will provide additional capacity for Suncor liquids as well as for liquids from the other oil sands producers' off-gas. The expected in-service date for this pipeline is April 2012. The pipeline will have the potential to transport up to 19 750 m^3/d, as needed, with the construction of additional pump stations.

NOVA Chemicals Corporation (NOVA Chemicals) signed a long-term agreement on March 28, 2011, with Williams for a feedstock supply of ethane/ethylene mix from the off-gas produced at oil sands upgrading facilities. The ethane/ethylene mix will be transported to Joffre, Alberta, via the Joffre Feedstock Pipeline from the Edmonton area.

Also, Nova Chemicals signed a deal with Hess Corporation to purchase and transport ethane produced at the Tioga gas plant in North Dakota via a proposed new pipeline to Alberta. The expected startup of the planned Vantage Pipeline is the third quarter of 2012.

A second project under construction will extract NGLs from oil sands off-gas. The Aux Sable Heartland off-gas plant is expected to be in service by the summer of 2011. Shell Canada and Aux Sable have signed an agreement to process all of the off-gas from Shell's Scotford upgrader.

6.2.3 Ethane and Other Natural Gas Liquids Production—Forecast

Ethane volumes in Alberta are expected to remain flat at 2010 levels over the forecast period, as shown in **Figure S6.2**. New ethane supplies are expected from oil sands off-gas. Ethane supply is, to a large degree, a function of ethane demand. The four ethylene plants in the province that use ethane as a feedstock operated collectively at 72 per cent capacity utilization rate in 2010.

The ERCB expects that all ethane recovered in Alberta will be used in Alberta, even though export permits are in place to move small volumes of ethane outside of Alberta. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities; this is expected to continue through the forecast period. Small volumes of ethane may be imported from the U.S. to meet market demand.

Figure S6.2 also refers to the potential ethane supply from conventional natural gas and the ethane volumes that could be recovered from oil sands off-gas production. The ethane supply volumes from conventional gas are calculated based on the volume-weighted average ethane content of conventional gas in Alberta of 0.052 mol/mol and the assumption that 80 per cent of ethane could be recovered at processing facilities. Current processing plant capacity for ethane is about 60 10^3 m^3/d and is not a restraint to recovering the volumes forecast. Potential ethane supply from oil sands off-gas is calculated assuming an average ethane content of 12 per cent in the off-gas production volumes and an 80 per cent recovery rate of ethane.

The forecast ethane supply from conventional natural gas crosses over the demand curve around 2014, unchanged from last year's forecast. This forecast assumes that incremental ethane volumes required to meet demand will be available from off-gas.

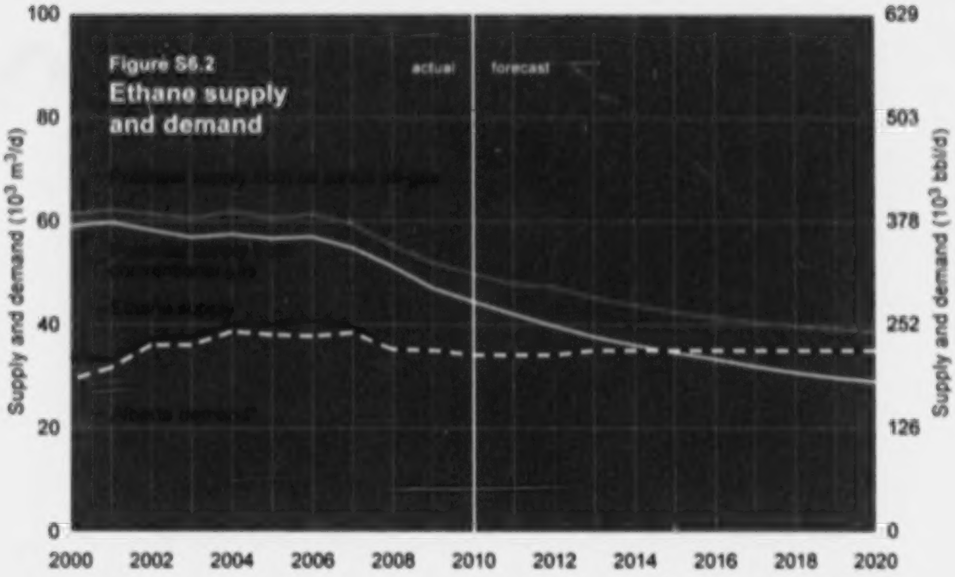


Figure S6.2
Ethane supply and demand

* Excludes solvent flood volumes

Over the forecast period, the ratios of propane, butanes, and pentanes plus liquid to marketable conventional gas are expected to increase as shown in **Table 6.5**. **Figures S6.2** to **S6.5** show forecast production volumes to 2020 for ethane, propane, butanes, and pentanes plus.

6.2.4 Demand for Ethane and Other Natural Gas Liquids

All of the specification ethane extracted in 2010 was used in Alberta as feedstock. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four plants using ethane as feedstock for the production of ethylene. The Joffre feedstock pipeline transports a range of feedstocks from Fort Saskatchewan to Joffre. These feedstocks supplement the ethane supplies now used at the petrochemical plants at Joffre, where three of the four ethylene plants are located. The fourth is in Fort Saskatchewan. To acquire ethane, the petrochemical industry pays a fee to NGL processing facility owners to extract and deliver ethane from natural gas streams processed at their facilities. The industry adds value to NGLs by upgrading them for use in the manufacture of products such as plastic, rope, and building materials.

The petrochemical industry in Alberta is benefiting from the low gas price environment since the price of ethane, the primary feedstock for ethylene production, is linked to natural gas prices. The Alberta ethylene industry continues to maintain its historical cost advantage for ethylene production compared with a typical propane or naptha cracking plant in the U.S. Gulf Coast. Prices of propane and other heavier gas liquids are linked to crude oil, which is currently trading at levels above $US100/bbl WTI. Historically, crude oil traded at six to seven times the price of natural gas. Now the difference is 25 times, an indication that natural gas and ethane are inexpensive as a feedstock to the petrochemical industry.

As shown in **Figure S6.2**, Alberta demand for ethane is projected to remain at 2010 levels of 34.2 10^3 m^3/d over the forecast period. For the purposes of this forecast, it was assumed that the existing ethylene plants will continue to operate at a 72 per cent capacity utilization rate and that no new ethylene plants requiring ethane as feedstock will be built in Alberta over the forecast period. Small volumes of ethane have historically been exported from the province, primarily for use as a buffer for pipeline ethylene shipments to eastern Canada. Since 2008 and the end of ethylene deliveries to Ontario in the Cochin pipeline, there have been no ethane removals from the province, and this expected to remain the case over the forecast period.

Figure S6.3 shows Alberta's demand for propane compared with the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Alberta propane demand increased slightly in 2010 to 3.5 10^3 m^3/d from 3.0 10^3 m^3/d in 2009. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying. Alberta propane demand is forecast to grow moderately by 1.7 per cent throughout the forecast period. As mentioned earlier, small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities; this is expected to continue throughout the forecast period.

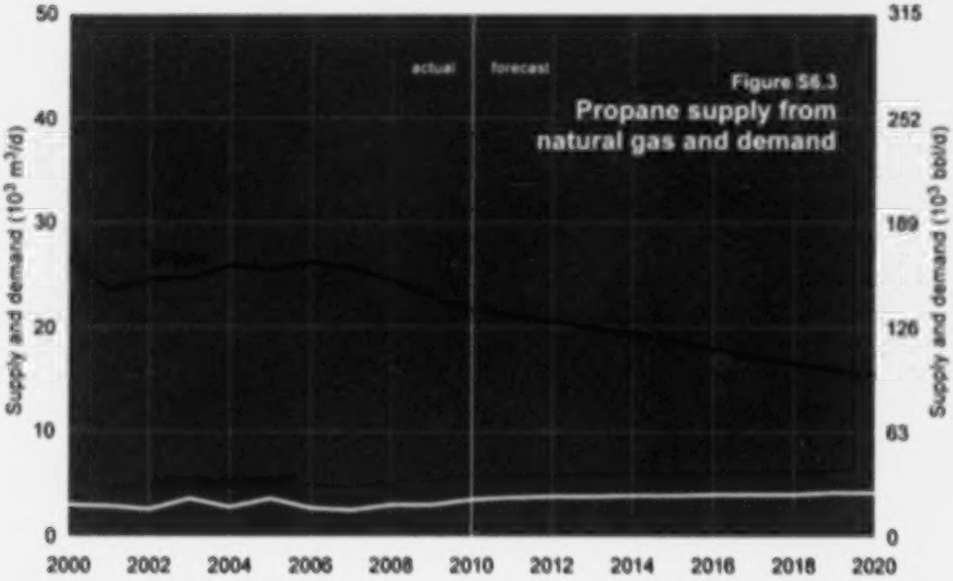


Figure S6.3
Propane supply from natural gas and demand

* Excludes solvent flood volumes.

Figure S6.4 shows Alberta demand for butanes compared with the total available supply from gas processing plants. As with propane, the difference between Alberta butane requirements and total supply represents volumes used by markets outside of Alberta. Butanes are used as refinery feedstock as well as in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate. In 2010, Alberta demand, excluding solvent flood demand, was 4.6 10^3 m^3/d, down from 5.4 10^3 m^3/d in 2009. Alberta demand for butanes is forecast to remain constant at 4.6 10^3 m^3/d over the forecast period.

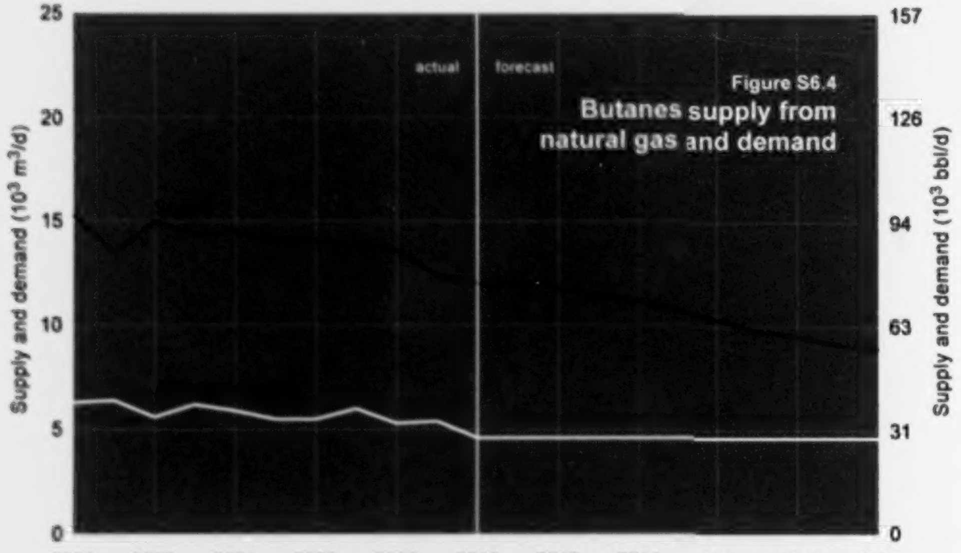


Figure S6.4
Butanes supply from natural gas and demand

* Excludes solvent flood volumes.

The largest use of Alberta pentanes plus is as diluent in the blending of heavy crude oil and bitumen to facilitate their transport to market by pipeline. Diluent increases the API gravity and reduces the viscosity of heavy crude oil and bitumen.

Figure S6.5 shows the ERCB estimate of Alberta demand for pentanes plus used for diluent compared with the total available supply. Pentanes plus are also used as feedstock for the refinery in Lloydminster; these small volumes (0.9 10^3 m^3/d in 2010) are not included in the figure. Pentanes plus demand is estimated based on assumed blending factors and heavy oil and bitumen production.

Demand for pentanes plus is expected to remain strong due to continued high diluent requirements. As a result, pentanes plus demand as diluent is forecast to increase from 41.2 10^3 m^3/d in 2010 to 106.8 10^3 m^3/d in 2020.

As illustrated in **Figure S6.5**, the diluent demand is estimated to have exceeded Alberta supply around 2004. The current estimated demand reflects the inadequate Alberta supply of pentanes plus since 2004, which has resulted in the use and assessment of alternative sources (imports) and types of diluent.

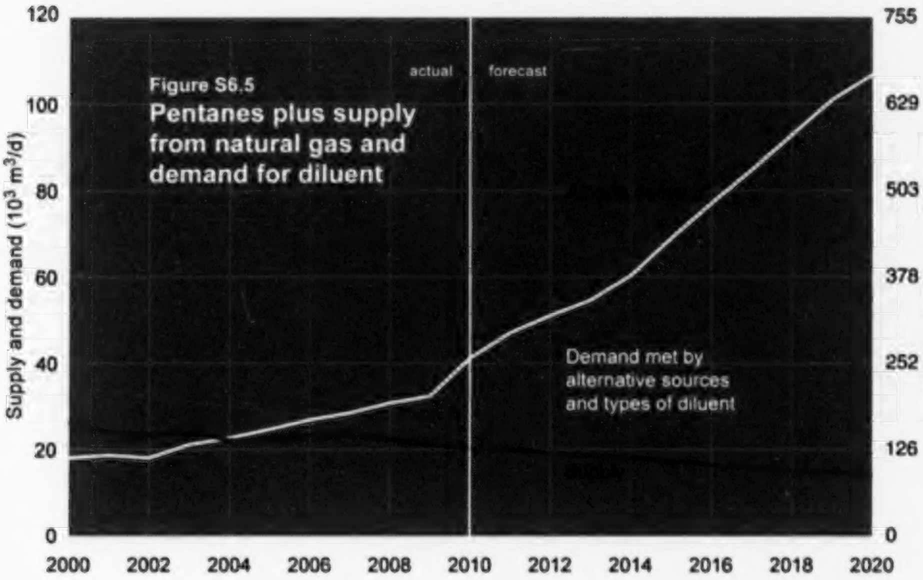


Figure S6.5
Pentanes plus supply from natural gas and demand for diluent

* Excludes solvent flood volumes.

Alberta imports of pentanes plus are expected to rise rapidly over the next 10 years with growing oil sands demand. The following list outlines current and future sources of diluent from outside Alberta that will be needed to facilitate transportation of bitumen that is not upgraded to synthetic crude oil to markets.

- In 2010, Alberta pentanes plus supply was augmented by 9.0 10^3 m^3/d of pentanes plus from outside of Alberta.
- Enbridge Inc.'s Southern Lights Pipeline, which transports diluent from Chicago to Edmonton, was placed in service in July 2010. The 20-inch-diameter pipeline has a capacity to deliver 28.6 10^3 m^3/d of diluent to Alberta.
- Cenovus Energy has the capability to import up to 4.0 10^3 m^3/d of offshore condensate to help transport its growing oil sands production to U.S. markets. With access to the Kitimat, B.C., terminal facility, Cenovus imports diluent and transports it by rail to an Alberta pipeline connection that feeds its oil sands operations.
- Enbridge is pursuing a commercial arrangement to build a condensate pipeline capable of initially transporting 23.8 10^3 m^3/d of offshore condensate from Kitimat to Edmonton.

7 // SULPHUR

HIGHLIGHTS

Established sulphur reserves decreased 2.6 per cent from 2009 to 2010 because of a decrease in remaining natural gas and crude bitumen reserves.

Sulphur production from gas processing declined 10 per cent from 2009 to 2010 to 3.2 million tonnes, while sulphur production from crude bitumen increased marginally.

Total sulphur production fell from 5.2 million tonnes in 2009 to 5.0 million tonnes in 2010.

Sulphur is a chemical element found in conventional natural gas, crude bitumen, and crude oil. The sulphur is extracted and sold primarily for use in making fertilizer. Currently, most produced sulphur is derived from the hydrogen sulphide (H_2S) contained in about 20 per cent of the remaining established reserves of conventional natural gas.

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2010, to be 176.5 million tonnes (10^6 t), down 2.6 per cent from 2009. **Table 7.1** shows the changes in sulphur reserves over the past year. The ERCB does not estimate sulphur reserves from sour crude oil, as only a very small portion of Alberta's sour crude oil is refined in the province.

Table 7.1 Reserve and production change highlights (10^6 t)

	2010	2009	Change[a]
Initial established reserves from			
Natural gas	269.1	268.9	+0.2
Crude bitumen[b]	178.5	178.5	0.0
Total	**447.6**	**447.4**	**+0.2**
Cumulative production from			
Natural gas	246.6	243.4	+3.2
Crude bitumen	24.5	22.8	+1.7
Total	**271.1**	**266.2**	**+5.0**
Remaining established reserves from			
Natural gas	22.5	25.5	-3.0
Crude bitumen[b]	154.0	155.7	-1.7
Total	**176.5**	**181.2**	**-4.7**
Annual production	5.0	5.2	-0.2

[a] Any discrepancies are due to rounding.

[b] Reserves of elemental sulphur from bitumen mines under active development as of December 31, 2010. Reserves from the entire surface mineable area are larger.

7.1.2 Sulphur from Natural Gas

The ERCB recognizes 22.5 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2010, a decrease of 12 per cent from 2009. Remaining established sulphur reserves has been calculated using a provincial recovery factor of 97 per cent, which was determined taking into account plant efficiency, acid gas flaring at plants, acid gas injection, and solution gas flaring.

The ERCB's sulphur reserve estimates from natural gas are shown in **Table 7.2**. Fields containing the largest recoverable sulphur reserves are listed individually. Fields with significant volumes of sulphur reserves in 2010 are Caroline, Crossfield East, and Waterton. Together, these account for 6.1 10^6 t, or 27 per cent, of the remaining established reserves of sulphur from natural gas.

The ERCB estimates the ultimate potential for sulphur from natural gas to be 394.8 10^6 t, which includes 40 10^6 t from ultrahigh H_2S pools currently not on production. Based on initial established reserves of 269.1 10^6 t, this leaves 125.7 10^6 t of yet-to-be-established reserves from future discoveries of conventional gas.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of current upgrading operations in which bitumen is converted to synthetic crude oil (SCO), an average of 90 per cent of the sulphur contained in the crude bitumen is either recovered in the form of elemental sulphur or remains in byproducts of upgrading bitumen such as coke.

It is currently estimated that 218.3 10^6 t of sulphur will be recoverable from the 5.39 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the surface-mineable area. These sulphur reserves were estimated by using a factor of 40.5 tonnes of sulphur per 10^3 m^3 of crude bitumen. This ratio reflects both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology recovers more sulphur than does alternative carbon-rejection technology. With the later technology more of the sulphur in the bitumen remains in upgrading residues and less is converted to H_2S.

If less of the mineable crude bitumen reserves is upgraded with the hydrogen-addition technology than is currently estimated, or if less of the mineable reserves is upgraded in Alberta, the total sulphur reserves will be less.

In 2010, the Nexen/OPTI Long Lake Upgrader continued it's operations of upgrading in situ bitmen to SCO, resulting in the production of small quantities of sulphur, most of which was not marketed. The ERCB will include in situ upgrading projects in future reports as they come on-stream, in **Table 7.1.** At the same time, however, those mining projects that do not upgrade bitumen will have their sulphur reserves removed from the provincial total. If all future bitumen production were to be upgraded in Alberta, the sulphur recovered could exceed 2 billion tonnes.

Table 7.2 Remaining established reserves of sulphur from natural gas as of December 31, 2010[a]

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[b] (%)	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Bighorn	3 300	6.5	257	348
Blackstone	1 522	10.1	202	273
Brazeau River	9 741	5.0	607	823
Burnt Timber	1 316	19.1	387	525
Caroline	7 331	13.6	1 415	1 919
Coleman	1 032	26.6	410	556
Crossfield	3 046	15.0	678	920
Crossfield East	2 210	29.1	1 144	1 551
Elmworth	20 722	1.5	375	508
Garrington	3 151	5.2	210	285
Hanlan	7 352	8.7	843	1 143
Jumping Pound West	4 140	6.6	345	468
Kaybob South	15 833	1.1	211	287
Limestone	3 300	12.5	564	765
Marsh	1 205	16.5	273	371
Moose	2 073	13.5	372	505
Okotoks	992	26.4	427	579
Panther River	2 509	7.2	235	318
Pembina	23 361	1.1	355	482
Pine Creek	7 658	2.6	228	309
Rainbow South	2 884	6.6	272	369
Ricinus West	1 259	32.1	674	915
Waterton	5 256	22.3	1 926	2 612
Wildcat Hills	4 055	3.2	152	206
Wimborne	2 023	8.5	204	277
Windfall	2 253	11.7	361	489
Subtotal	139 524	7.2	13 127	17 801
All other fields	885 571	0.4	3 487	4 748
Total	1 025 095	1.4	16 614	22 549

[a] Any discrepancies are due to rounding.

[b] Volume-weighted average.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only some of the production from surface-mineable established crude bitumen reserves will be upgraded by the Suncor, Syncrude, Shell, Albian Sands, Shell Jackpine, CNRL Horizon, Suncor/Total/Teck Fort Hills, and Imperial Kearl projects. The ERCB's estimate of the initial established sulphur reserves from these active projects is 178.5 10^6 t, representing 82 per cent of estimated recoverable sulphur from the remaining established crude bitumen in the total surface-mineable area. A total of 24.5 10^6 t of sulphur has been produced from these projects, leaving 154.0 10^6 t of remaining established reserves. During 2010, 1.7 10^6 t of sulphur were produced from the currently producing projects.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Production—2010

There are three sources of sulphur production in Alberta: sour natural gas processing, bitumen upgrading to SCO, and crude oil refinement into petroleum products. In 2010, Alberta produced 4.96 10^6 t of sulphur, of which 3.22 10^6 t were derived from sour gas, 1.73 10^6 t from upgrading of bitumen to SCO, and just 12 thousand (10^3) t from oil refining. The total sulphur production in 2010 represents a decrease of 5.1 per cent from 2009 levels due to a decline in natural gas production and less H_2S in the gas. Most of Canada's sulphur is produced in Alberta.

7.2.1.1 Sulphur Production from Natural Gas

Figure S7.1 shows historical sulphur production from gas processing plants. Sulphur production volumes are a function of raw gas production, sulphur content, and gas plant recovery efficiencies. As conventional sour gas production declines, less sulphur will be recovered from gas processing plants. This trend is evident in the steep decline in sulphur production from gas processing plants since 2000, as shown in **Figure S7.1**. The most notable sulphur production declines in 2010 were Shell Canada Limited at Caroline, as a result of extended plant downtime, and Husky Oil Operations Ltd. at Ram River—down 281 10^3 t and 60 10^3 t, respectively.

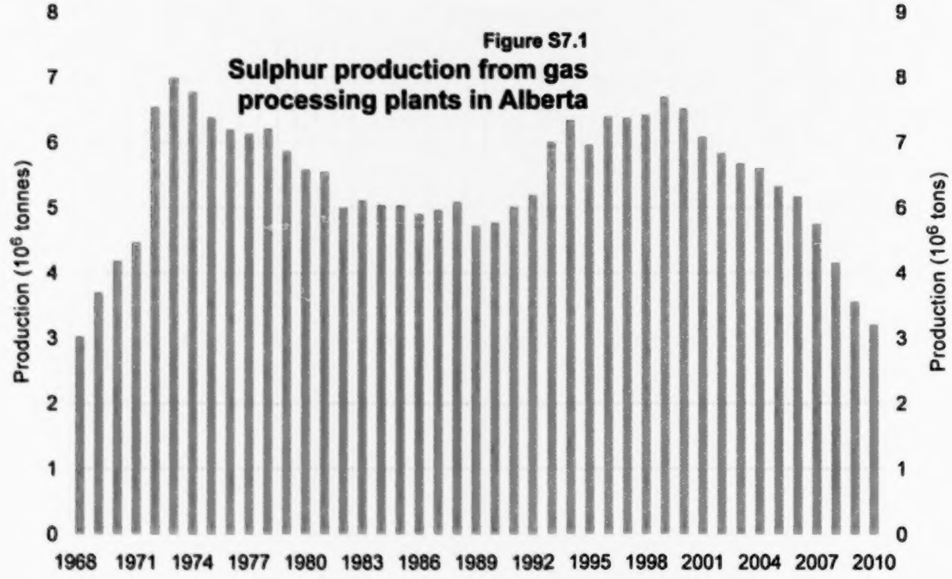
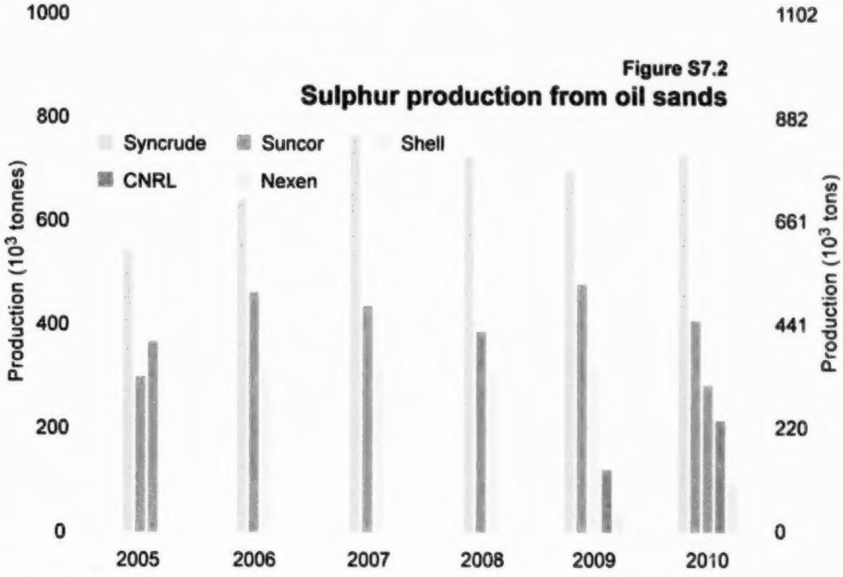


Figure S7.1
Sulphur production from gas processing plants in Alberta

Sulphur stockpiles stored as solid blocks at gas processing plants have been drawn down significantly in recent years as the result of an increase in global sulphur demand. **Figure 15** in the Overview section illustrates historical sulphur closing inventories at gas processing plants and oil sands operations, as well as sulphur prices. Inventory blocks of sulphur at gas processing plants in Alberta were 2.47 10^6 t at year-end 2010, down from 3.44 10^6 t at year-end 2009.

7.2.1.2 Sulphur Production from Oil Sands

Historical sulphur production from the five oil sands upgrader operations is shown in **Figure S7.2**. Total production of 1.73 10^6 t in 2010 is up 5 per cent from 2009 production of 1.65 10^6 t as a result of increased production at Nexen/OPTI Long Lake and CNRL Horizon, now both in their first full year of service.



7.2.2 Sulphur Production—Forecast

Total Alberta sulphur production from sour gas, crude oil, and bitumen upgrading and refining is depicted in **Figure S7.3**. Sulphur production from sour gas is expected to decrease from 3.22 10^6 t to 2.07 10^6 t, or by about 36 per cent, by the end of the forecast period. However, sulphur recovery from bitumen upgrading and refining is expected to increase from 1.74 10^6 t to 3.07 10^6 t. The large increase in sulphur production from bitumen upgrading in 2012 over 2011 is attributed to the start-up of a new Shell upgrader and the completion of repairs to the CNRL Horizon upgrader following the major fire in early 2011.

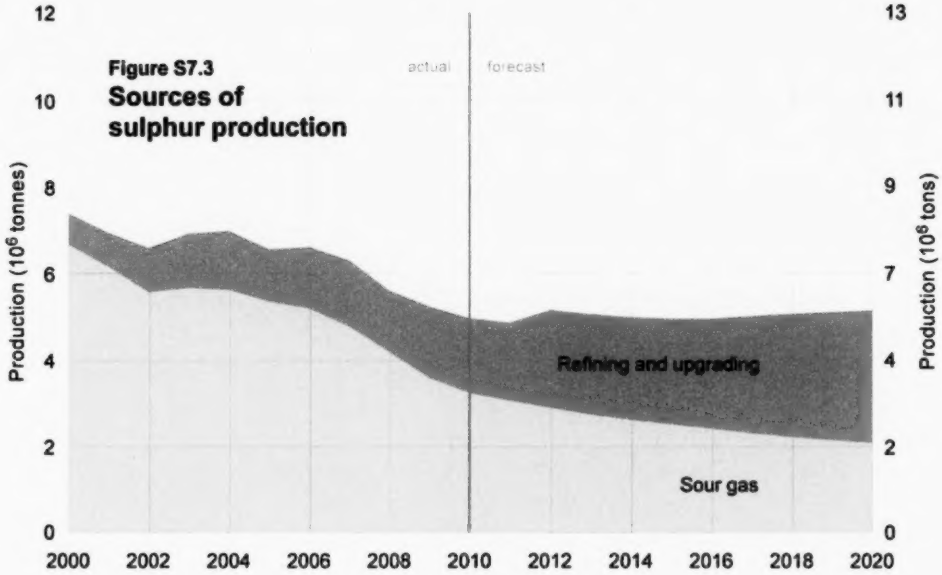


Figure S7.3
Sources of sulphur production

Sulphur recovery from Alberta refineries is forecast to increase from 12 10^3 t in 2010 to 18 10^3 t by 2020. This year's forecast of sulphur production from refineries is lower than the previous year's due to a change in the forecast assumption. Previously, our assumption was that sulphur recovery would increase over time because of changes in refinery feedstock from conventional crude oil to bitumen, which generally has higher sulphur content. The increase in sulphur production at refineries has not, however, materialized, even though refinery feedstock has changed. Therefore, the current forecast is based on the assumption that Alberta refineries will continue to recover volumes of sulphur similar to what they have recovered historically.

7.2.3 Sulphur Demand

Disposition of sulphur within Alberta in 2010 was 584 10^3 t, up from 336 10^3 t in 2009. The volume in 2010 may include Alberta plant-to-plant transfers that could cause disposition of sulphur in the province to be higher than actual volumes consumed. Therefore, forecast volumes are kept constant at 2009 levels.

Sulphur is used in the production of phosphate fertilizer and kraft pulp and in other chemical operations. About 89 per cent of the sulphur marketed by Alberta producers in 2010 was shipped outside the province. Exports offshore and to the U.S. constituted 61 and 26 per cent of the total sulphur deliveries, respectively, with the remainder being delivered to the rest of Canada. **Figure S7.4** shows the historical Canadian export volumes sent to markets outside of North America.

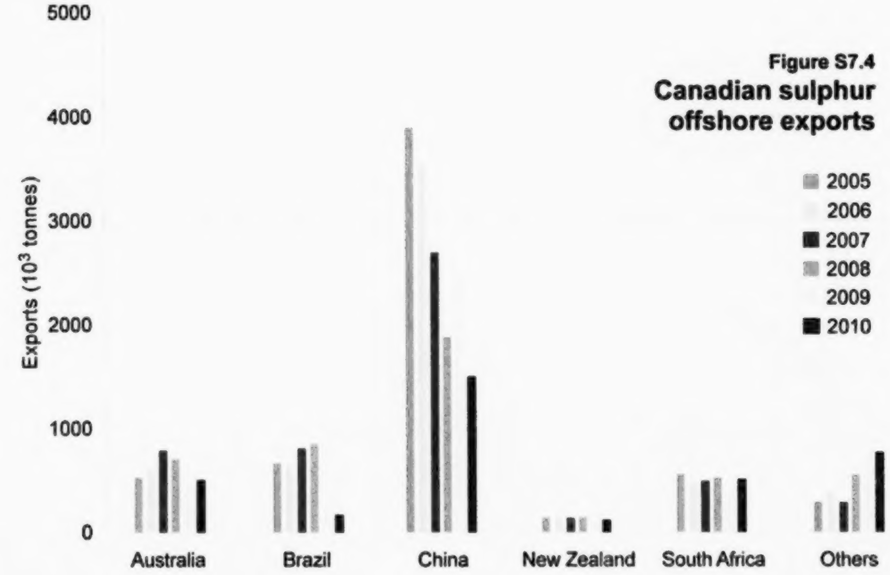


Figure S7.4
Canadian sulphur offshore exports

China is the world's largest importer of sulphur, which is used primarily for making sulphuric acid to produce phosphate fertilizer. China imported 10.5 million tonnes of sulphur in 2010, with Canada accounting for 14 per cent of imports. Canada is the second largest supplier of sulphur to China, behind Saudi Arabia, with 1.5 million tonnes delivered in 2010.

Shipments out of Vancouver, Canada in 2010 have fallen from 2009 levels as a result of tight sulphur supply. Sulphur output from the Shell Caroline gas plant and associated sulphur facilities was disrupted in late 2010 as a result of a after a series of mechanical problems. The increase in prices for sulphur in offshore markets also helped curtail demand.

In 2010, sulphur prices began in the $US60 to $US80/t range, steadily increasing throughout the year, and were reported in the $US120/t to $US160/t range by December 2010. By early 2011, Canadian suppliers were signing contracts for sulphur at continued high market prices in the range of $US180/t to $US200/t. Prices are recovering as global economies strengthen.

Because sulphur is fairly easy to store, imbalances between production and disposition have traditionally been accommodated through net additions to or removals from sulphur stockpiles. If demand exceeds supply, sulphur is withdrawn from stockpiles; if supply exceeds demand, sulphur is added to stockpiles.

Figure S7.5 shows the historical and forecast total supply and demand of sulphur, including inventory additions and withdrawals.

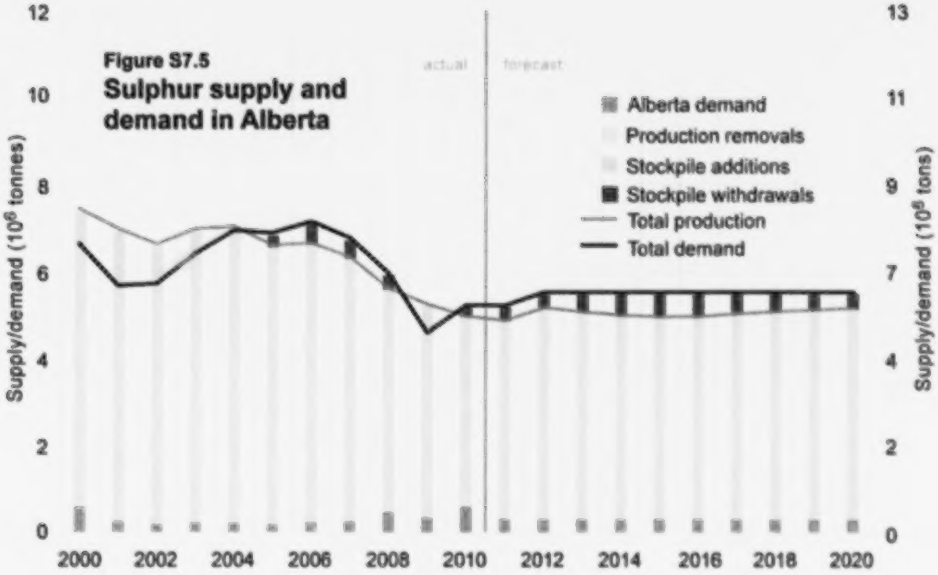


Figure S7.5
Sulphur supply and demand in Alberta

In the early part of the previous decade, weak global sulphur demand resulted in less demand for Alberta exports, and as a result, Alberta built a significant stockpile of sulphur. Since 2004, supply and demand have generally been in balance, with small withdrawals from inventory stockpiles. The forecast assumes that, on average, this situation will continue as declining production from natural gas processing plants is replaced by sulphur recovery from the bitumen upgrading industry, and the global call on Alberta sulphur supplies will approximate demand.

8 COAL

HIGHLIGHTS

Remaining established reserves under active development decreased by 39 million tonnes, or 4 per cent of the total, due to the closing of the Whitewood mine.

Subbituminous coal production decreased 3.5 per cent in 2010, mainly as a result of the Whitewood closure.

Exports of metallurgical coal to Asian markets remained strong.

Coal is a combustible sedimentary rock with greater than 50 per cent organic matter. Coal occurs in many formations across central and southern Alberta, with lower-energy-content coals in the plains region, shifting to higher-energy-content coals in the foothills and mountain regions.

Production of coal from mines is called raw coal. Some coal, particularly that from the mountain and foothills regions of Alberta, needs to be processed prior to marketing; this processed coal is referred to as clean coal. Clean coal (normally sold internationally) and raw coal from the plains region (normally sold within Alberta) are termed marketable coal. In this report, "reserves" refers to raw coal unless otherwise noted.

The possible commercial production of synthetic gas from coal (synthetic coal gas) in Alberta is being investigated and the ERCB is planning to have legislation in place in 2011 for regulating in situ coal gasification (ISCG) development. Consequently, this section has been expanded this year to include an analysis of Alberta's coal resources for possible ISCG use. A discussion of ISCG is given in Section 8.1.2.3.

The following coal reserves and production information summarizes and marginally updates the material found in the ERCB serial publication *ST31: Reserves of Coal, Province of Alberta* (2000 edition). See that publication for more detailed information and a greater understanding of the parameters and procedures used to calculate established coal reserves.

8.1 Reserves of Coal

8.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of all types of coal in Alberta at December 31, 2010, to be 33.3 gigatonnes[1] (Gt) (36.8 billion tons). Of this amount, 22.7 Gt (or about 68 per cent) is considered recoverable by underground mining methods, and 10.5 Gt is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 per cent is within permit boundaries of mines active in 2010. **Table 8.1** gives a summary by rank of resources and reserves from 244 coal deposits.

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[1] Giga = 10^9.

8 COAL

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---

[1] Giga = 10^9.

Minor changes in remaining established reserves from December 31, 2009, to December 31, 2010, resulted from additions to cumulative production. During 2010, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.005 Gt, 0.009 Gt, and 0.025 Gt respectively.

Table 8.1 Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2010[a] (Gt)

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves
Low- and medium-volatile bituminous[b]				
Surface	1.74	0.811	0.242	0.569
Underground	5.06	0.738	0.110	0.628
Subtotal	**6.83[c]**	**1.56[c]**	**0.352**	**1.21[c]**
High-volatile bituminous				
Surface	2.56	1.89	0.186	1.704
Underground	3.30	0.962	0.047	0.915
Subtotal	**5.90[c]**	**2.88[c]**	**0.233**	**2.65[c]**
Subbituminous[d]				
Surface	13.6	8.99	0.803	8.19
Underground	67.0	21.2	0.068	21.1
Subtotal	**80.7[c]**	**30.3[c]**	0.871	**29.4**
Total	**93.7[c]**	**34.8[c]**	1.46[e]	**33.3[c]**

[a] Tonnages have been rounded to three significant figures.

[b] Includes minor amounts of semi-anthracite.

[c] Totals for resources and reserves are not arithmetic sums but are the result of separate determinations.

[d] Includes minor lignite.

[e] Any discrepancies are due to rounding.

8.1.2 In-Place Resources

There was no change to the in-place resource estimate over the previous year.

8.1.2.1 Geology and Coal Occurrence

Coal occurs extensively in Alberta throughout the sequence of Jurassic- to Paleocene-aged formations. The coal-bearing formations underlie about 300 000 square kilometres or almost half of Alberta. **Figure R8.1** shows the subcrops of most of the coal-bearing formations, and their equivalents, in Alberta.

Coal, with or without thin clastic layers called partings, occurs in vertical accumulations called seams. Coal maturity, or rank, is measured on the basis of calorific value for lower-ranked coals and carbon content for high-rank coals. Coals of all rank groups, from lignite to semi-anthracite, occur in Alberta.

The ERCB has designed three coal-bearing regions, shown in **Figure S8.1**, based on rank, geology, and topography, so as to group coals of similar methods of recovery and markets. The mountain region exhibits complex geologic structures and steep topography with higher-ranked coal amenable to export for metallurgical purposes. The foothills region exhibits moderately complex structures and hilly topography with moderate-ranked coals amenable to export for thermal purposes. The plains region is the largest and exhibits generally flat lying seams and flat or incised plateau topography with lower ranked coals amenable for domestic thermal purposes. The plains region contains about 88 per cent of Alberta's coal, most of which is of subbituminous rank.

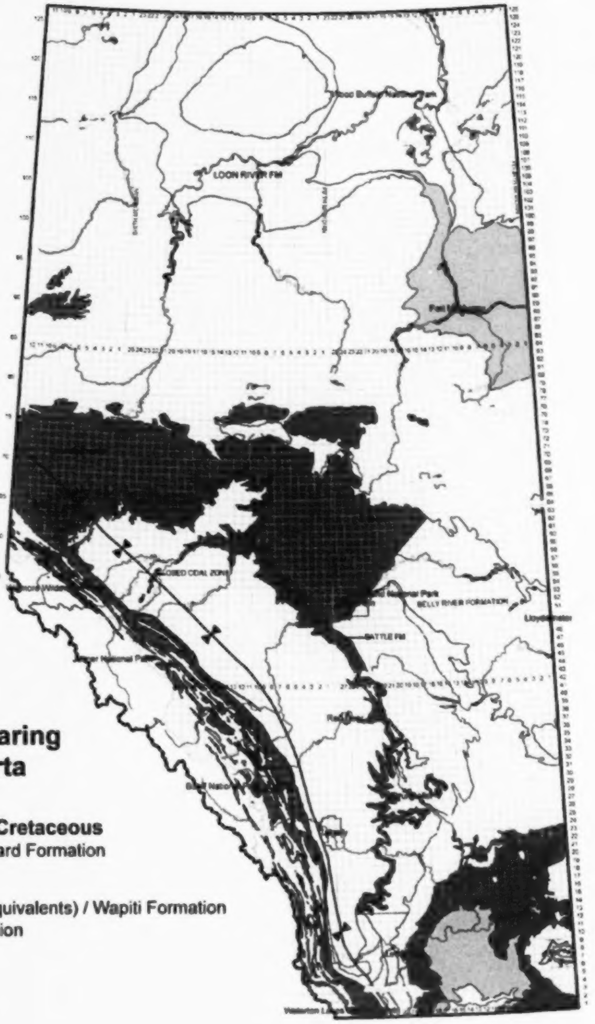


Figure R8.1
Significant coal-bearing formations in Alberta

Paleocene and Upper Cretaceous
■ Coalspur Formation / Scollard Formation

Upper Cretaceous
■ Brazeau Formation (and equivalents) / Wapiti Formation
Horseshoe Canyon Formation
■ Oldman Formation
░ Foremost Formation

Lower Cretaceous
■ Luscar Group
░ Mannville Group

Lower Creataceous and Upper Jurassic
▨ Kootenay Group

Figure S8.1

Producing coal mines in Alberta

○ **Surface coal mine** ● **Underground coal mine**

Mountain Region

Low- to medium-volatile bituminous coals

① Grande Cache
② Cheviot

Foothills Region

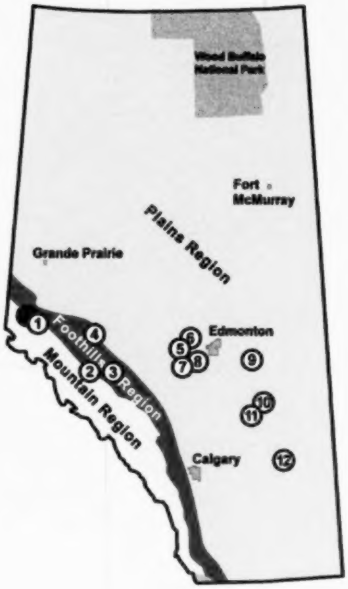
High-volatile bituminous coals

③ Coal Valley
④ Obed

Plains Region

Subbituminous coals

⑤ Highvale
⑥ Whitewood
⑦ Burtonsville Island
⑧ Genesee
⑨ Dodds
⑩ Vesta
⑪ Paintearth
⑫ Sheerness



8.1.2.2 Coal Mineability

In general, shallow coal is mined more economically by surface than by underground methods and is classified as surface-mineable. At some stage of increasing depth and strip ratio,[2] the economic advantage passes to underground mining; this coal is considered underground-mineable. The classification scheme used to differentiate between surface- and underground-mineable coal is very broadly based on depth and strip ratio, designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

These classifications are used to categorize total coal in place. Further analysis is done to determine which portions of this coal may be developed and which portion of that coal may be recovered. Some in-place coal, such as underground thin seams, is unlikely to be developed by mining methods but is included in the total because of past production. Additionally, some of the currently classified underground coal may become the target of commercial ISCG development. At such time, the ERCB will split the underground classification into mineable and in situ components.

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[2] Strip ratio is the amount of overburden that must be removed to gain access to a unit amount of coal.

8.1.2.3 In Situ Coal Gasification

There are three types of coal gasification processes: in situ coal gasification, surface facility gasification from mined coal, and biological modification of in situ coal seams, referred to as biogenic gas. Surface facility gasification is derived from conventionally mined coal, and those mineable coal reserves would be included in the tables above. Currently, gasification facilities do not exist in Alberta and therefore there is no production to address in this section. Biogenic gasification is not included in this report since it is highly speculative at this time.

New developments in technology for coal extraction are occurring in Alberta, with two pilots for ISCG approved, one of which was partially operational in 2010. ISCG technology uses wellbores to access coal seams at depth. Future development may take place at depths below those currently assumed to be mineable.

ISCG consists of thermal reduction of coal to simpler hydrocarbons that can be produced up a wellbore. Any ISCG-derived gas would, by its nature, incorporate any coalbed methane gas volumes (see Section 5) contained within the targeted coals. Currently, ISCG synthetic coal gas is limited to a small quantity of experimental production, and therefore, neither synthetic coal gas volumes nor their associated coal resource tonnages are yet included in this report. However, Alberta's vast quantities of coal would supply a large resource base should development prove commercial, and the ERCB anticipates detailing such volumes and tonnage in future reports.

8.1.3 Established Reserves

Several techniques, in particular geostatistical methods, have been used for calculating in-place volumes, with separate volumes calculated for surface- and underground- mineable coal. Certain parts of deposits are considered nonrecoverable for technical, environmental, or safety reasons, and therefore have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal, as well as the thicker underground classes of coal seams.

A recovery factor of 90 per cent has been assigned to the remaining in-place surface-mineable area, followed by an additional small coal loss at the top and a small dilution at the bottom of each seam.

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because there is seldom sufficient information to outline such areas, it is assumed that, in addition to the coal previously excluded, only a percentage of the remaining deposit areas would be mined. Thus a "deposit factor" has been determined whereby, on average, only 50 per cent of the remaining deposit area is considered to be mineable in the mountain region, 70 per cent in the foothills, and 90 per cent in the plains—the three regions designated by the ERCB within Alberta where coals of similar quality and mineability are recovered.

A mining recovery factor of 75 per cent is then applied to both medium (1.5 to 3.6 metres [m]) and thick (>3.6 m) seams, with a maximum recoverable thickness of 3.6 m applied to thick seams. Thin seams (0.6 to <1.5 m) are not currently considered recoverable by underground methods.

Table 8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2010.

Table 8.2 Established resources and reserves of raw coal under active development as of December 31, 2010

Rank Mine	Permit area (ha)[a]	Initial in-place resources (Mt)[b]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves (Mt)
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	23	131
Grande Cache	4 250	199	85	30	55
Subtotal	**11 705**	**445**	**239**	**53**	**186**
High-volatile bituminous					
Coal Valley	17 865	572	331	144	187
Obed	7 590	162	137	43	94
Subtotal	**25 455**	**734**	**468**	**187**	**281**
Subbituminous					
Paintearth and Vesta	5 120	163	121	96	25
Sheerness	7 000	196	150	84	66
Dodds	425	2	2	1	1
Burtonsville Island	150	0.5	0.5	0.1	0.4
Highvale	12 140	1 021	764	387	377
Genesee	7 320	250	176	80	96
Subtotal[c]	**32 155**	**1 633**	**1 214**	**648**	**565**
Total	**69 315**	**2 812**	**1 921**	**888**	**1 032**

[a] ha = hectares.

[b] Mt = megatonnes; mega = 10^6.

[c] Any discrepancies are due to rounding.

8.1.4 Ultimate Potential

A large degree of uncertainty is associated with estimating an ultimate potential, and new data could substantially alter results. Two methods have been used to estimate the ultimate potential of coal: volume and trend analysis. The volume method gives a broad estimate of area, coal thickness, and recovery ratio for each coal-bearing horizon, while the trend analysis method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

To avoid large fluctuations of ultimate potentials from year to year, the ERCB has adopted the policy of using the figures published in the 2000 edition of *ST31* and adjusting them slightly to reflect the most recent trends. **Table 8.3** gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potential. No change to ultimate potential has been made for

2010. It is anticipated that further resource development for ISCG will occur primarily in the "subbituminous underground" category in **Table 8.3**.

Table 8.3 Ultimate in-place resources and ultimate potentials[a] (Gt)

Coal rank Classification	Ultimate in-place	Ultimate potential
Low- and medium-volatile bituminous		
Surface	2.7	1.2
Underground	18	2.0
Subtotal	**21**	**3.2**
High-volatile bituminous		
Surface	10	7.5
Underground	490	150
Subtotal	**500**	**160**
Subbituminous		
Surface	14	9.3
Underground	1 400	460
Subtotal	**1 500**	**470**
Total	**2 000[b]**	**620**

[a] Tonnages have been rounded to two significant figures, and totals are not arithmetic sums but are the result of separate determinations.

[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

8.2 Supply of and Demand for Marketable Coal

Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous, and thermal bituminous. Subbituminous coal is mainly used for electricity generation in Alberta. Metallurgical bituminous coal is exported and used for industrial applications, such as steel production. Thermal bituminous coal is also exported and used to fuel electricity generators in distant markets. The higher calorific content of bituminous thermal coal makes it possible to economically transport the coal over long distances. While subbituminous coal is burned without any form of upgrading, both types of export coal are sent in raw form to a preparation plant, whose output is referred to as clean coal. Subbituminous raw coal and clean bituminous coal are collectively known as marketable coal.

8.2.1 Coal Production—2010

The locations of coal mine sites in Alberta are shown in **Figure S8.1**. In 2010, twelve mine sites produced coal in Alberta, as shown in **Table 8.4**. These mines produced 31.7 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 77 per cent of the total, bituminous metallurgical 9 per cent, and bituminous thermal coal the remaining 14 per cent.

Six large mines and two small mines produce subbituminous coal. The large mines serve nearby electric power plants, while the small mines supply residential and commercial customers. Because of the need for long-term supply to power plants, most of the coal reserves are dedicated to the power plants.

Three surface mines and one mine with both surface and underground recovery produce the provincial supply of metallurgical and thermal grade coal.

Table 8.4 Alberta coal mines and marketable coal production in 2010

Owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Sherritt International Corp.	Genesee	Genesee	5.6
Sherritt International Corp.	Sheerness	Sheerness	3.3
	Paintearth & Vesta	Halkirk/Cordel	3.1
Sherritt International Corp.	Highvale	Wabamun	12.2
	Whitewood	Wabamun	0.2
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.100
Keephills Aggregate Ltd.	Burtonsville Island	Burtonsville Island	0.031
Subtotal			**24.5**
Bituminous metallurgical coal			
Teck Resources Limited	Cheviot	Mountain Park	1.5
Grande Cache Coal Corp.	Grande Cache	Grande Cache	1.4
Subtotal			**2.9**
Bituminous thermal coal			
Sherritt International Corp.	Coal Valley	Coal Valley	3.4
	Obed	Obed	0.9
Subtotal			**4.3**
Total			**31.7**

8.2.2 Coal Production—Forecast

The projected production for each of the three types of marketable coal is shown in **Figure S8.2**. In March 2010, the Whitewood mine ceased operations, which resulted in a 3.5 per cent reduction in subbituminous coal production. By 2020, total production is expected to decrease by about 2.0 per cent, from 31.7 Mt in 2010 to 31.0 Mt in 2020. Subbituminous coal production shows a drop of 4.5 per cent over the forecast period, while thermal and metallurgical bituminous coal production continue to remain flat. An increase in production from metallurgical coal is possible if proposed mines open within the forecast period.

8.2.3 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electric generation plants, and the production from these mines can be affected by the commissioning and closures of power generation plants.

In 2010, the federal government announced a policy that would require all coal-fired power plants to either be retired by the end of their economic life or their power purchase agreement or meet stringent emissions requirements. New federal regulations arising from the policy are expected to take effect in 2015, and the ERCB has considered this in forecasting the electricity supply from coal.

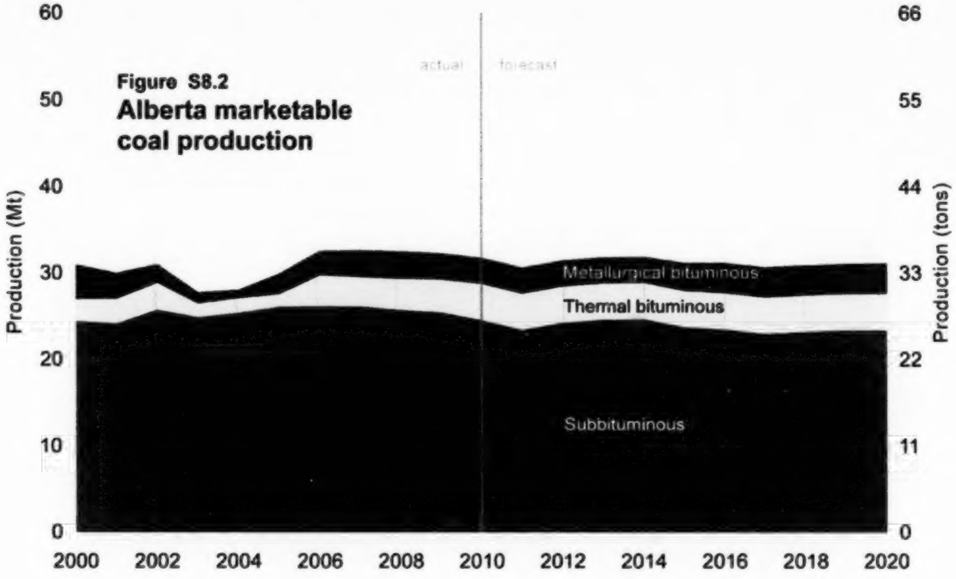

Figure S8.2
Alberta marketable coal production

In December 2010, Sundance Units 1 and 2 operated by TransAlta went out of service, impacting 560 MW of coal-fired capacity. In February 2011, TransAlta announced that the units could not be economically restored to service and declared force majeure on both units.

The last remaining power generation unit at the Wabamun plant site with a capacity of 279 MW was decommissioned in March 2010. The new power generation unit at Keephills plant with a capacity of 450 MW is expected to be in service in the second quarter of 2011. Upgrades to increase the capacity of Keephills Units 1 and 2 by 23 MW each are scheduled for late October 2011 and May 2012 respectively.

Alberta's metallurgical coal primarily serves the Asian steel industry, with Japan being the country that imports the most metallurgical and thermal coal. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta export coal producers. Floods in Australia in late 2010 forced 75 per cent of its coal mines (both metallurgical and thermal coal) to halt production. The reduction in world production affected second quarter price negotiations for Alberta exporters and price increases are expected in the near term.

9 // ELECTRICITY

HIGHLIGHTS

In 2010, Alberta's demand for electricity increased by 1.2 per cent compared with a 0.5 per cent increase in 2009.

In 2010, coal-fired electricity generating capacity decreased by 279 MW because of the retirement of Wabamun 4. Wind-powered generation capacity increased by 214 MW with the addition of three new wind farms.

In 2010, the annual average pool price increased to $50.88/MWh from $47.81/MWh in 2009.

The ERCB forecasts electricity supply and demand and its forecasts are essential in determining the future domestic demand for some of Alberta's primary energy resources. Of particular importance are the relationships between electricity supply and natural gas and coal resources. Power plants that use these fuels supplied over 90 per cent of the electricity generated within Alberta in 2010.

While the ERCB regulates the oil, gas, and coal industries, the Alberta Utilities Commission (AUC) regulates utilities and oversees the building, operating, and decommissioning of electrical generation as well as the fair routing, tolls, and tariffs of regulated utilities.

The competitive wholesale electricity market is facilitated by the Alberta Electric System Operator (AESO) and monitored by the Market Surveillance Administrator (MSA). In addition to managing the electricity sold into the Alberta power pool, the AESO is responsible for planning Alberta's transmission system. The MSA monitors Alberta's electricity market for fairness and balance in the public interest by ensuring that the market operates fairly, efficiently, and in an openly competitive manner.

9.1 Electricity Generating Capacity

9.1.1 Provincial Summary

The ERCB refers to electricity generating capacity in terms of maximum continuous rating (MCR), which is defined as the maximum output that a generating station is capable of producing continuously under normal conditions over a year and is usually expressed in the number of megawatts (MW).[1] Alberta's fuel mix of available electricity generating capacity is composed of coal, natural gas, hydroelectric power, and "other," such as wind and biomass. A relatively small amount of capacity is from diesel and fuel oil-fired generators, which are a source of backup power for industrial use. Alberta also relies on transmission interties with neighbouring provinces, enabling the import and export of electricity. The capacity of the various components of Alberta's electricity industry, including a forecast to 2020, is illustrated in **Figure 9.1**.

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[1] The AESO reports maximum capability (MC) in terms of the maximum MW that a facility may generate for shorter periods of time.

In 2010, 69 per cent of the natural gas-fired capacity in the province was classified as cogeneration. Cogeneration is the combined production of electricity and thermal energy using natural gas as a fuel source. Thermal energy is often used in manufacturing processes, heating buildings, the production of steam for in situ oil production, and crude oil refining and upgrading processes. Therefore, cogeneration plants (often referred to as cogen plants) are often sited alongside an industrial facility.

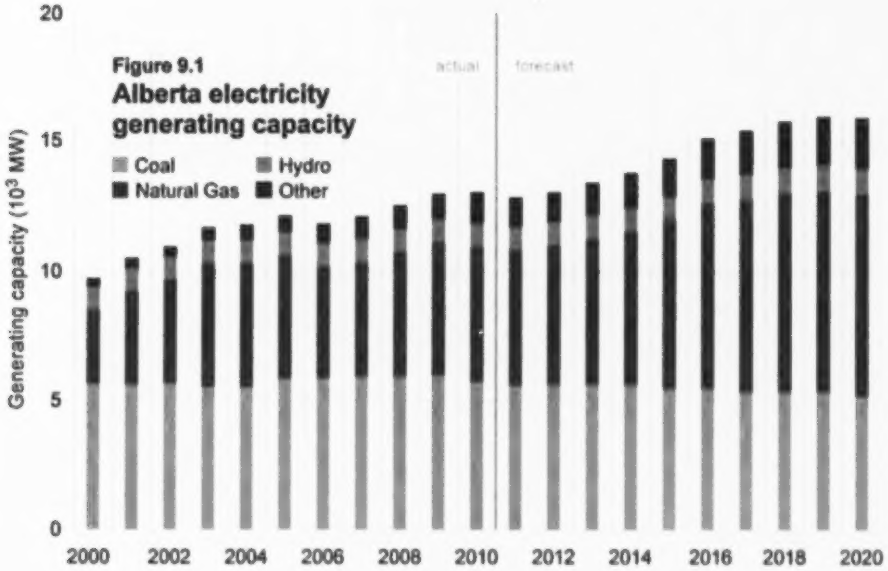

Figure 9.1
Alberta electricity generating capacity

At the end of 2010, Alberta power generating capacity was 13 071 MW consisting of 109 electric power generating facilities that each had a capacity of 5 MW or more. In 2010, coal-fired facilities accounted for 44 per cent of Alberta's total electric generation capacity compared to 58 per cent in 2000. Natural gas-fired facilities accounted for 40 per cent compared to 30 per cent in 2000.

In 2010, Alberta's electric power generation capacity increased by 320 MW, or about 2.4 per cent. Most of the additional capacity was from three new wind power facilities totaling 214 MW. TransAlta brought on Summerview 2 and Ardenville (66 MW each) and NextEra brought on Ghost Pine Wind Farm (81.6 MW).

In addition, Connacher Oil and Gas Ltd. commissioned a 13.1 MW gas-fired cogeneration unit to supply the Algar SAGD (steam-assisted gravity drainage) project, and AltaGas commissioned a 15 MW cogeneration facility at Harmattan. The remaining additions came from various small uprates at existing coal-fired generation plants. The Wabamun 4 coal power plant with 279 MW capacity was officially retired on March 31, 2010. This power plant was initially commissioned in 1967 and was the last remaining power plant in operation at the Wabamun coal site.

In mid-December 2010, the Sundance 1 and 2 coal-fired generating units were withdrawn from service. In February 2011, TransAlta issued a notice of termination for both units under the Sundance A Power Purchase Agreement (PPA)[2] indicating that the units cannot be economically restored to service.

The permanent loss of the Sundance units has reduced coal-fired generation capacity in the province by about 560 MW temporarily. The new coal-fired Keephills 3 unit (450 MW), scheduled to come on stream in the second quarter of 2011, will replace most of the lost capacity. Both of these changes are included in the capacity forecast shown in **Figure 9.1**.

Power projects for which applications have been submitted for regulatory review and that are considered in our forecast are summarized in **Table 9.1**. The project names, capacities, and applied for start-up dates are based on information obtained as of late February, 2011. A number of projects have not come on stream as expected based on their applied-for start-up dates. These projects are also included in **Table 9.1** and are also considered in the forecast. Although some uncertainty surrounds the exact timing of additional oil sands-related facilities, the majority are expected to proceed with project start-up within the forecast period and are therefore included. The ERCB projects electricity generating capacity in Alberta to be over 15 900 MW by the end of the forecast period, which is slightly higher than last year's forecast of 15 500 MW in 2019.

The loss of the Sundance coal fired units sooner than anticipated has accelerated the trend of the province's generation feedstock mix from coal to natural gas. As a result, new natural gas-fired cogeneration facilities are the largest contributors to the growth in electricity generating capacity over the forecast period. The commissioning of new gas-fired cogeneration facilities coincides with the development of Alberta's oil sands resources. Cogeneration is a source of steam and power, both requirements for oil sands projects. A significant number of operators have installed or are planning to install cogeneration as an economical way of generating both steam and electricity. By 2020, the capacity of natural gas-fired power and cogeneration units is forecast to total more than 7800 MW and account for 49 per cent of Alberta's total available capacity.

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[2] PPAs were introduced to facilitate the transition of the electricity generating industry from a regulated market to a competitive market. PPAs were auctioned off as long-term rights to sell power from utility plants built during the era of full regulation (before 1996). PPAs allowed the owners of the generating plants to recover their costs and earn a specified rate of return. Electricity generating units built after January 1, 1996, are not subject to PPAs, and the electricity they generate can be bought or sold directly on the market.

Table 9.1 Power plant applications greater than 5 MW, 2010-2020

Power plant by applied-for in-service date	Fuel type	Location	Proposed capacity (MW)
Past applied-for in-service date			
Deerland peaking station (Phase 1)	Natural gas	Lamont County	90
Deerland peaking station (Phase 2)	Natural gas	Lamont County	90
Irma generation facility	Natural gas	Wainwright MD	8
Morinville generation facility	Natural gas	Sturgeon County	8
Prairie Home 1 wind turbines	Wind	Warner County	9
2011			
University of Calgary	Natural gas	City of Calgary	18
Firebag in situ cogen 3	Natural gas	Wood Buffalo MD	170
Wintering Hills	Wind	Wheatland County	88
Keephills 3	Coal	Parkland County	450
Keephills 2 uprate	Coal	Parkland County	23
Weyerhauser uprate	Biomass	Grand Prairie	48
2012-2020			
STP McKay in situ cogen	Natural gas	Wood Buffalo MD	17
Carmon Creek in situ cogen	Natural gas	Northern Sunrise County	185
Christina Lake in situ cogen 2	Natural gas	Wood Buffalo MD	85
Firebag in situ cogen 4 and 6	Natural gas	Wood Buffalo MD	170
Kearl oil sands cogen 1 and 2	Natural gas	Wood Buffalo MD	170
Fort Hills oil sands cogen	Natural gas	Wood Buffalo MD	170
MacKay expansion in situ cogen	Natural gas	Wood Buffalo MD	165
Jackpine oils sands cogen	Natural gas	Wood Buffalo MD	160
Horizon oil sands cogen 2	Natural gas	Wood Buffalo MD	86
Joslyn oil sands cogen	Natural gas	Wood Buffalo MD	85
Long Lake South in situ cogen	Natural gas/syngas	Wood Buffalo MD	85
Nabiye oil sands cogen	Natural gas	Cold Lake	160
Daishowa-Marubeni	Natural gas	Peace River	30
Saddlebrook Power Station	Natural gas	Foothills MD	338
Enmex Shepard Project	Natural gas	Calgary	800
Bonnybrook Energy Centre	Natural gas	Calgary	165
TransCanada	Natural gas	Calgary	40
Dunvegan hydro project	Hydro	Fairview MD	100
Heritage Wind Farm	Wind	Pincher Creek MD	300
Old Man 2 River Wind Farm	Wind	Pincher Creek MD	46
Wild Rose Wind Farm 1	Wind	Cypress County	204
Medicine Hat Box Springs	Wind	Medicine Hat	16
Hand Hills	Wind	Starland County	99
Castle Rock Ridge Wind Farm	Wind	Pincher Creek MD	115
Halkirk Wind Project	Wind	Paintearth County	150
Blackspring Ridge Project	Wind	Vulcan County	300
Maxim HR Milner	Coal	Greenview MD	500
Keephills 1 uprate	Coal	Parkland County	23
Mustus Energy	Biomass	Mackenzie County	35
Total proposed generation (2010-2020)			**5812**

9.1.2 Electricity Generating Capacity by Fuel

9.1.2.1 Coal

In 2010, the capacity of coal-fired generation units was over 5700 MW and accounted for 44 per cent of Alberta's generating capacity.

TransAlta has filed regulatory applications with the AUC to uprate the Keephills 1 and 2 coal-fired plants by 23 MW each in 2011 and 2012, respectively. Also, Maxim Power Corporation has filed regulatory applications with the AUC to construct a new supercritical power plant facility with 500 MW of capacity next to the existing HR Milner generating station. The TransAlta/Capital Power Keephills 3 coal-fired plant with 450 MW capacity commenced construction in February 2007 and is expected to be commissioned in the second quarter of 2011. The Keephills 3 coal-fired plant incorporates supercritical boiler technology featuring higher boiler temperatures and pressures. Combined with a high-efficiency turbine, the unit will require less fuel and have lower emissions on a per MWh basis than other plants. The capital cost of Keephills 3, including mine capital, is expected to be about $1.9 billion.

On June 23, 2010, the federal minister of environment announced a new regulation for coal-fired electricity generation plants. According to the new regulation, power companies would have to close their coal-fired facilities at 45 years of age or at the end of the power purchase agreement, whichever is later. Under this proposed legislation, companies would be prohibited from making investments to extend the lives of those plants unless emission levels can be reduced to the emission levels of natural gas combined cycle plants. The new regulation encourages electric utilities to transition towards lower- or non-emitting types of generation such as high-efficiency natural gas, renewable energy, or thermal power with carbon capture and storage (CCS). The proposed regulation is scheduled to take effect on July 15, 2015. The ERCB forecast assumes that this new regulation will be enacted.

9.1.2.2 Natural Gas

In 2010, natural gas-fired generating capacity exceeded 5200 MW and accounted for 40 per cent of Alberta's total electricity capacity. Over the next 10 years, Alberta's natural gas-fired electric capacity is projected to increase by 2593 MW and represent 49 per cent of Alberta's total generating capacity.

The ERCB 10-year forecast for new natural gas-fired cogeneration power plants that are built on-site at oil sands operations amounts to 1892 MW. These plants account for 73 per cent of the increase in natural gas-fired capacity in the province. **Table 9.1** lists the new gas cogeneration projects, most of which will be in the Municipal District of Wood Buffalo.

In addition to the proposed oil sands gas cogeneration facilities, several natural gas-fired peaking facilities have recently been built. Peaking plants are designed to be available on short notice and can respond quickly to varying market conditions. ENMAX has applied to build two new natural gas-fired power plants in the Calgary area, with the Shepard plant designed for 800 MW of generating capacity and the Bonnybrook plant designed for 165 MW. These projects are considered in the projection of electricity supply.

9.1.2.3 Hydroelectric Power

Hydroelectric generation capacity in Alberta has been essentially unchanged since 2003 at almost 900 MW, accounting for 7 per cent of total generation capacity in 2010. About 860 MW of this capacity, owned by TransAlta, is located along the Bow and North Saskatchewan rivers.

The proposed TransAlta Dunvegan 100 MW power plant located on the Peace River has been approved, but construction has not begun. The plant capacity has, however, been included in the projection.

9.1.2.4 Other

About 8 per cent of Alberta's current electricity capacity is classified as "other," which includes biomass and wind. Biomass electricity is derived from plant or animal material, such as wood, straw, peat, or manure. In Alberta, the most common fuel for biomass generation is waste wood. Forestry industries typically burn waste wood as a fuel source to generate electricity and thermal energy. In 2010, Alberta biomass capacity was 340 MW, contributing 2.6 per cent of Alberta's total electricity capacity.

Wind-powered electric generation capacity has increased significantly over the last decade, from 37 MW in 2000 to 805 MW in 2010. Lack of transmission infrastructure had been a significant barrier for new wind capacity in southern Alberta, but in 2010 AltaLink energized the southwest 240 kilovolt[3] (kV) project, a 90-kilometre transmission line between Pincher Creek and Lethbridge, Alberta. In September 2009, the AESO received regulatory approval to expand the system in phases that together could generate 2700 MW.

9.2 Electricity Supply and Demand

This section discusses the supply and demand for electricity within Alberta. On the supply side, the stock of electricity, or capacity, is measured in watts, while the flow of electricity, or generation, is measured in watt hours. In this report, electricity demand is measured in gigawatt hours (GWh).

Electricity generation is the amount of electricity produced within a certain time period. For instance, if an electricity plant with a rated capacity of 100 MW operated at its maximum potential for one day, it would supply 2.4 GWh of electricity; however, if the same plant only supplied 1.8 GWh of electricity on a given day, the plant would be using 75 per cent of its potential capacity.

To forecast electricity generation, the ERCB uses a list of existing and proposed electricity generating units operating within the province, their electricity generating capacities and operating characteristics, a merit or stacking order, hourly customer load profiles, and projected electricity demand. The proposed generating units and generating capacities are discussed in the previous section.

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[3] kilo = 10^3.

The operating capacity of an existing electricity generating unit is determined using its historical operating parameters, such as outage and capacity utilization rates. In the oil sands sector, the forecast of electricity generation from new generation is ramped up in a phased approach that corresponds with the expected on-site load at certain phases of bitumen and synthetic crude oil (SCO) production.

The stacking order of electricity generation refers to the order in which electricity from each generating unit is offered in or sold to the electricity grid. The lowest marginal cost producers, which include wind turbines, hydroelectric dams, and some base coal-fired generation, are expected to offer in electricity generation first. Higher marginal cost producers, such as natural gas-fired turbines, offer electricity into the grid at times of peak demand.

The electricity generation forecast complements the electricity demand forecast by incorporating hourly load profiles and the ERCB forecast of electricity demand for each year. There is an hourly load profile for each year that corresponds to the forecast total load. By incorporating hourly loads, generating units are dispatched hourly, accounting for periods of high load and low load throughout each year.

In this report, Alberta's electricity demand includes electricity sales reported by electricity distributors to agricultural, residential, commercial, and industrial customers; the direct use of electricity by industrial consumers that obtain their power directly from power plants located on site or near their facilities; and purchases of electricity by customers set up to directly purchase electricity from the Alberta power pool.

The ERCB uses customer segments and econometric modeling to forecast electricity demand. The key driver of residential and commercial electricity demand is population. Industrial customers are examined in greater detail to adequately account for electricity demand in this sector. In the oil sands sector, projections are based on bitumen and SCO production forecasts and the types of projects (in situ or mining).

9.2.1 Electricity Generation

Installed electricity generation capacity in 2010 was 13 071 MW, enough to supply about 114 000 GWh of electricity if plants are operated at full capacity. However, total electricity generation capacity is not continuously available to meet demand. Generation units are sometimes unavailable due to scheduled and unscheduled maintenance, forced outages, technical limitations (e.g., of wind turbines), or economic reasons. The current forecast projects that electric power generation capacity in Alberta will increase by more than 2879 MW over the next 10 years, an increase from last year's forecast increase of 2450 MW, and consistent with the higher electricity demand forecast.

Figure 9.2 illustrates total electricity generation, actual generation, and forecast generation to 2020, within Alberta by fuel type, including electricity from gas cogeneration plants that is not sold into the Alberta Interconnected Electric System (AIES). In 2010, total electricity generation reached 70 586 GWh, a 1.9 per cent increase from the 69 262 GWh reported in 2009. Between 2000 and 2010, electricity generation in Alberta grew by 12 741 GWh, or an average2.3 per cent per year. By 2020, total electricity generation is forecast to be over 94 000 GWh, higher thanlast year's forecast of over 88 000 GWh by 2019.

In 2010, coal-fired power plants generated almost 59 per cent of the province's electricity, while natural gas and hydro accounted for 34 and 2 per cent, respectively. The remaining 5 per cent was generated by wind and other renewable sources. Natural gas cogeneration plants dedicated to the oil sands sector generated 15 691 GWh of electricity in 2010, of which 10 431 GWh (67 per cent) of the electricity generated was used on site. The remaining electricity geneated was sold into the power pool. By 2020, coal-fired power plants are forecast to generate 42 per centof the province's electricity, while natural gas and hydro are forecast to account for 47 and 3 per cent,respectively. The remaining 8 per cent is projected to come from wind power and other renewable sources.

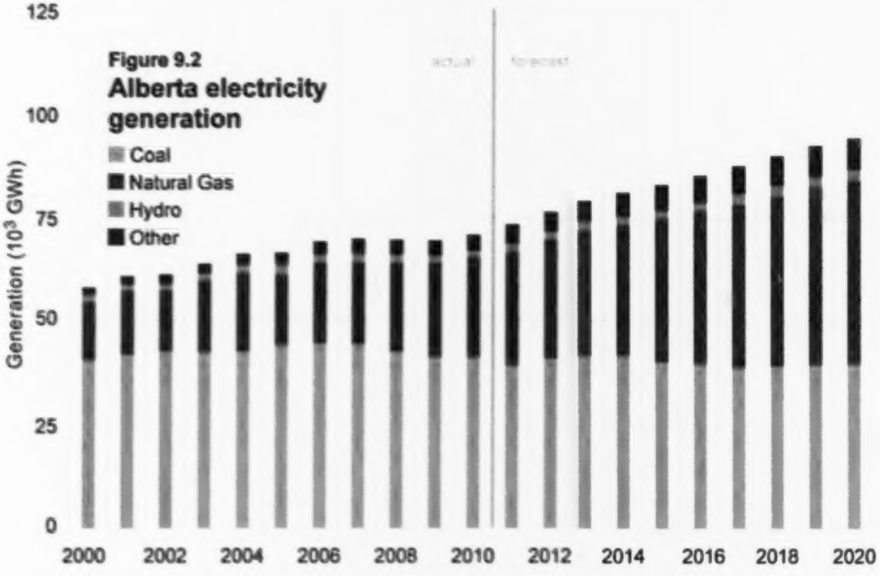

Figure 9.2
Alberta electricity generation

9.2.2 Electricity Transfers

Alberta's transmission lines are connected with British Columbia (B.C.) and Saskatchewan. Alberta is interconnected with the B.C. transmission system through a 500 kV line between Langdon, Alberta, and Cranbrook, B.C., and two 138 kV lines between Coleman, Alberta, and Natal, B.C. Since B.C. is connected with the United States (U.S.) Pacific Northwest, the Alberta-B.C. intertie allows Alberta to indirectly trade electricity with the U.S. The 230 kV direct current electrical tie with Saskatchewan enables Alberta to import or export about 150 MW.

The Alberta-B.C. interconnection was designed to operate at transfer capacities of 1200 MW from B.C. to Alberta and 1000 MW from Alberta to B.C. Operations on the Alberta-B.C. intertie are typically below these capacities.

In addition to the transmission ties, a natural gas-fired electricity generation unit in Fort Nelson (northern B.C.) supplies power to its surrounding communities and sells surplus electricity into the Alberta grid.

Figure 9.3 illustrates Alberta's electricity transfers from 2000 to 2010. Over the last decade, Alberta has generally been a net importer of electricity, except in 2001, when the electricity price differentials between Alberta and the Pacific Northwest favoured Alberta and resulted in net exports for the year. In 2010, Alberta imported 2366 GWh of electricity from both Saskatchewan and B.C., an increase of 9 per cent, or 186 GWh, from 2009. Electricity exports decreased 10 per cent, or 49 GWh, to 464 GWh in 2010 relative to 2009. As a result, Alberta's net imports of electricity were 1901 GWh in 2010, which is less than 4 per cent of total Alberta demand. The exports from Alberta were almost exclusively to the B.C. side (90 per cent), which absorbed 416 GWh of power. The imports were also weighted toward the B.C. tie (85 per cent).

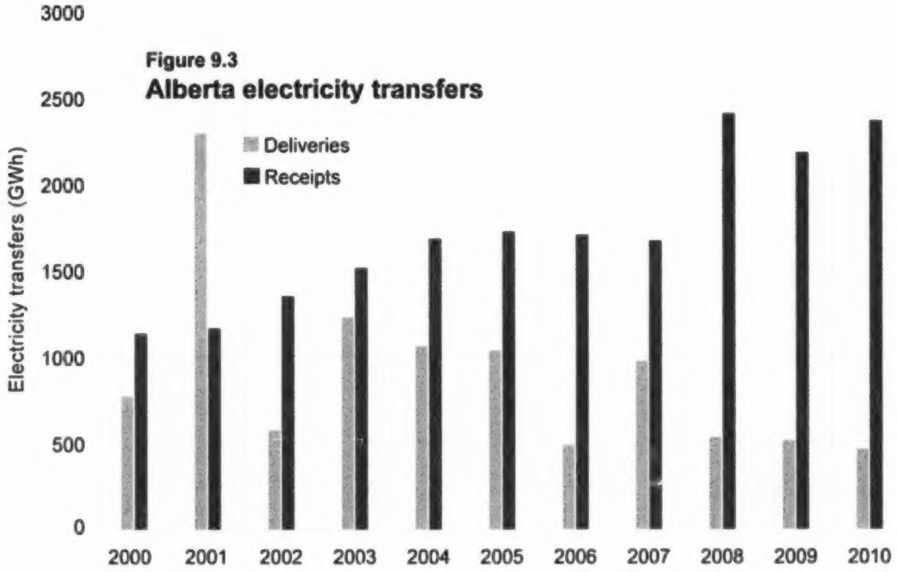

Figure 9.3
Alberta electricity transfers

In December 2009, Montana Alberta Tie Ltd. began construction of a 230 kV merchant electric transmission line between Lethbridge, Alberta and Great Falls, Montana. Completion of the transmission line has been delayed by legal proceedings.

The ERCB supply/demand projection for electric power projects forecasts that Alberta will be a net importer of electricity over the forecast period as a result of market price differentials and operational upsets.

9.2.3 Electricity Demand in Alberta

The demand for electricity is often reported by the AESO as two series. The first, the AIES, is the sum of all reported electricity sales (residential, commercial, industrial, and farm) and transmission and distribution losses.[4] The second, AIL, incorporates AIES and behind-the-fence load, which can be characterized as industrial load from on-site generation prior to sales to the power pool.

The ERCB 10-year load forecast is prepared based on examination of four sectors of the economy—residential, commercial, industrial, and farm—that account for most of the AIL forecast presented in this section. These demand forecasts are generally based on the ERCB forecast of economic and population growth, projections of oil sands development, and the expected production of conventional oil and natural gas.

Figure 9.4 illustrates Alberta's electricity demand. It includes retail sales from electricity distribution companies by sector, direct connect sales, and industrial on-site electricity volumes. Alberta's total

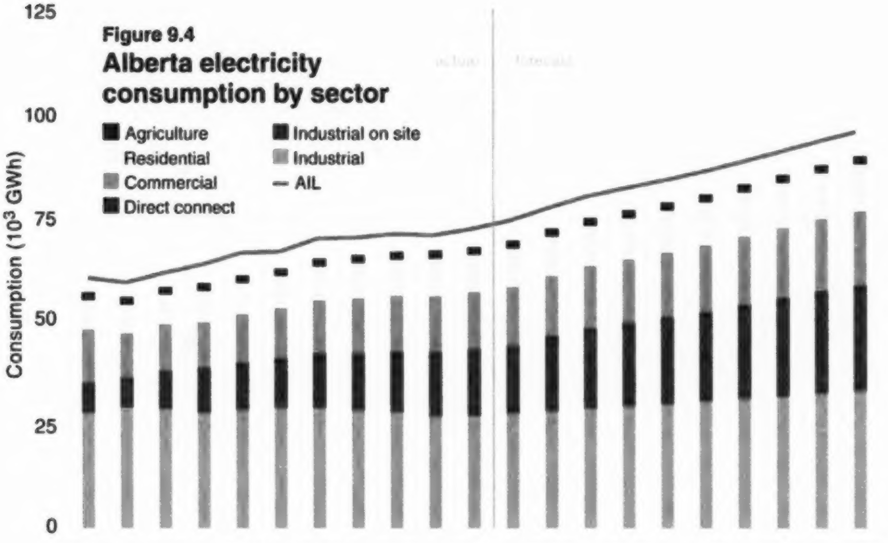

Figure 9.4
Alberta electricity consumption by sector

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[4] Most of Alberta's electricity is sold through electricity distribution companies. However, a few customers purchase a small amount of power directly from the power pool. In 2010, direct connect sales were about 1751 GWh, or 2 per cent of total AIL demand.

electricity demand for all sectors (excluding transmission and distribution losses) amounted to 68 011 GWh in 2010. Compared with 2009, this is an increase of 804 GWh, or 1.2 per cent.

Electricity distribution companies, including ATCO Electric, ENMAX Corporation, EPCOR, Fortis Alberta Inc.; cities and towns, including Lethbridge, Medicine Hat, Red Deer, Cardston, Fort Macleod, and Ponoka; and the municipality of Crowsnest Pass report their annual retail sales of electricity to the regulator.

In 2010, Alberta's electricity consumption from sales reported by electricity distributors was 51 603 GWh. This is a 0.5 per cent increase over the 51 328 GWh reported sold in 2009. Of these sales, about 52 per cent of the electricity consumed is sold to industrial customers, 27 per cent to commercial customers, 18 per cent to the residential sector, and 3 per cent to the farm sector.

Customer details provided by electricity retailers reveal that over 1.30 million residential customers consumed 9071 GWh of electricity in 2010. This resulted in an electricity intensity of 7.0 MWh per residential customer, slightly lower than the 7.1 MWh per customer of 2009 and higher than the historical five-year average of 6.9 MWh per residential customer. Residential demand was 2.44 MWh per capita in 2010, compared with 2.48 MWh in 2009, a decrease of 1.6 per cent. Consumption per capita has grown by an average of 0.6 per cent per year from 2000 to 2010.

The electricity usage of the average commercial customer was estimated to be 83.9 MWh in 2010, slightly lower than the 84.2 MWh in 2009 and lower than the five-year average of 87.3 MWh. Commercial electricity demand per capita averaged 3.69 MWh in 2010, a 0.2 per cent increase from 2009 and a 0.9 per cent increase per year on average since 2002.

Of the total electricity demand from all sectors, 78 per cent was sold through the AIES. In 2010, over 43 000 GWh, or 64 per cent, of the total electricity demand of all sectors was used by industrial consumers. About 29 000 GWh, or 66 per cent of the industrial load, was sold through the AIES as sales by electricity distribution companies and direct connect customers, while 14 657 GWh of the electricity requirements of the industrial sector was delivered through on-site power generation or cogeneration. Electricity demand for industries with cogeneration (e.g., oil sands and petrochemicals) increased by 3 per cent in 2010.

The forecast for AIL growth from 2011 onward is projected to average 2.8 per cent per year. By 2020, the AIL demand is forecast to be 95 990 GWh. Most of the proposed projects are projected to come on stream during the forecast period. Growth in oil sands electricity demand will be partially offset by lower growth in the conventional gas processing sector, with the result that total industrial electricity demand will grow by 3.6 per cent per year.

Over the next 10 years, growth in residential electricity demand is projected to average 2.4 per cent per year, tracking economic and population growth. Farm load is projected to be relatively constant at a level consistent with the average of the last 3 years. Electricity demand in the commercial sector will increase by 2.6 per cent per year, based on the ERCB's current economic forecast and population outlook for Alberta.

Alberta electric power generation is expected to match the projected growth in AIL demand of 2.8 per cent a year over the next decade. Over the forecast period, load growth will continue to be met primarily by existing and new natural gas-fired power plants.

9.2.4 Oil Sands Electricity Supply and Demand

Figure 9.5 depicts the balance between electricity supply and demand[5] within Alberta's oil sands sector. Electricity generation from the oil sands was forecast by applying the historical operating parameters of existing electricity cogeneration units to the proposed capacities of all current and future cogeneration units. Electricity demand is based on existing electricity intensities, electricity intensities outlined in regulatory applications, and the ERCB supply forecast for bitumen and SCO.

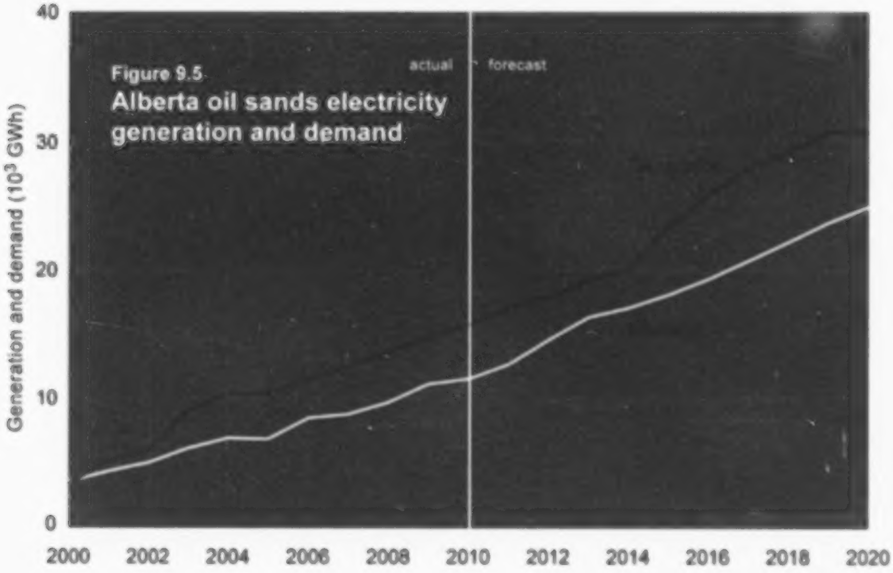
Figure 9.5
Alberta oil sands electricity generation and demand

Electricity cogeneration units at oil sands mines, bitumen upgraders, and in situ thermal projects typically provide required process steam and generate electricity to meet on-site electricity demand. Surplus electricity may be generated and sold to the power pool. **Table 9.2** displays 2010 electricity statistics by type of oil sands facility.

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[5] Historical electricity demand for in situ oil sands projects that do not operate cogeneration units was estimated using an assumption of 10 kilowatt hours per barrel.

increase by 2.6 per cent per year, based on the ERCB's current economic forecast and population outlook for Alberta.

Alberta electric power generation is expected to match the projected growth in AIL demand of 2.8 per cent a year over the next decade. Over the forecast period, load growth will continue to be met primarily by existing and new natural gas-fired power plants.

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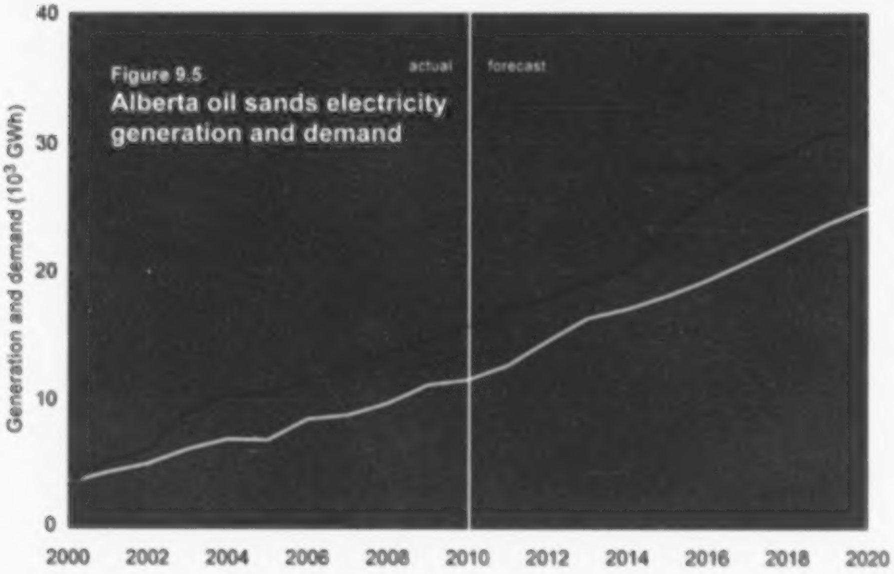
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[5] Historical electricity demand for in situ oil sands projects that do not operate cogeneration units was estimated using an assumption of 10 kilowatt hours per barrel.

Table 9.2 2010 electricity statistics at oil sands facilities

Project type	Capacity (MW)	Total generation (GWh)	Capacity utilization (per cent)	Generation used on site (GWh)
Mines and upgraders*	1446	9076	72	7029
Thermal in situ	908	6615	83	3402

* Mines and upgraders have been combined due to the confidential nature of some statistics.

Data for bitumen mining operations and upgraders indicate an annual capacity utilization of 72 per cent. Of the total electricity generated, 77 per cent was used on site and the remaining electricity was sold to the power pool.

Thermal in situ gas cogeneration facilities operated collectively at 83 per cent of their installed capacity, and 51 per cent of the total electricity generated was used on site, with the remaining output sold to the power pool.

Prior to 2010, seven thermal in situ oil sands operators obtained steam from on-site gas cogeneration facilities with installed electric generation capacities ranging from 80 to 180 MW. In 2010, the 13.1 MW gas cogeneration plant at the Connacher Algar in situ oil sands project began operating.

Cogeneration facilities are incorporated into the plans of some, but not all, of the oil sands projects included in the ERCB forecast of oil sands production and accompanying electricity supply and demand.

Appendix A Terminology, Abbreviations, and Conversion Factors

A.1 Terminology

API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Area	The area used to determine the bulk rock volume of the oil-, crude bitumen-, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.
Burner-tip	The location where a fuel is used by a consumer.
Butanes	In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus (*Oil and Gas Conservation Act*, Section 1(1)(c.1)).
Coalbed Methane	The naturally occurring dry, predominantly methane gas produced during the transformation of organic matter into coal.
Cogeneration Gas Plant	Gas-fired plant used to generate both electricity and steam.
Commingled	Commingled flow describes the production of fluid from two or more separate zones through a single conduit.
Compressibility Factor	A correction factor for nonideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.
Condensate	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(d.1)).
Connected Wells	Gas wells that are tied into facilities through a pipeline.
Crude Bitumen	A naturally occurring viscous mixture mainly of hydrocarbons heavier than pentane that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well (*Oil Sands Conservation Act*, Section 1(1)(f)).

Crude Oil (Conventional)	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen (*Oil and Gas Conservation Act*, Section 1(1)(f.1)).
Crude Oil (Heavy)	Crude oil is deemed to be heavy crude oil if it has a density of 900 kg/m^3 or greater.
Crude Oil (Light-Medium)	Crude oil is deemed to be light-medium crude oil if it has a density of less than 900 kg/m^3.
Crude Oil Netback	Crude oil netbacks are calculated from the price of WTI at Chicago less transportation and other charges to supply crude oil from the wellhead to the Chicago market. Alberta netback prices are adjusted for the U.S./Canadian dollar exchange rate, as well as crude quality differences.
Crude Oil (Synthetic)	A mixture mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds and is derived from crude bitumen. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so derived (*Oil and Gas Conservation Act*, Section 1(1)(t.1)).
Datum Depth	The approximate average depth relative to sea level of the midpoint of an oil or gas productive zone for the wells in a pool.
Decline Rate	The annual rate of decline in well productivity.
Deep-cut Facilities	A gas plant adjacent to or within gas field plants that can extract ethane and other natural gas liquids using a turboexpander.
Density	The mass or amount of matter per unit volume.
Density, Relative (Raw Gas)	The density relative to air of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.
Development Entities (DEs)	A development entity (DE) is an entity consisting of multiple formations in a specific area described in an order of the ERCB from which gas may be produced without segregation in the wellbore subject to certain criteria specified in Section 3.051 of the *Oil and Gas Conservation Regulations* (Order No. DE 2006-2).
Diluent	Lighter viscosity petroleum products that are used to dilute crude bitumen for transportation in pipelines.

Discovery Year	The year when drilling was completed of the well in which the oil or gas pool was discovered.
Economic Strip Ratio	Ratio of waste (overburden material that covers mineable ore) to ore (in this report refers to coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
Ethane	In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, Section 1(1)(h.1)).
Extraction	The process of liberating hydrocarbons (propane, bitumen) from their source (raw gas, mined oil sands).
Feedstock	In this report feedstock refers to raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.
Field	(i) The general surface area or areas underlain or appearing to be underlain by one or more pools, or (ii) the subsurface regions vertically beneath a surface area or areas referred to in subclause (i) (*Oil and Gas Conservation Act*, Section T1T (x)).
Field Plant	A natural gas facility that processes raw gas and is located near the source of the gas upstream of the pipelines that move the gas to markets. These plants remove impurities, such as water and hydrogen sulphide, and may also extract natural gas liquids from the raw gas stream.
Field Plant Gate	The point at which the gas exits the field plant and enters the pipeline.
Field/Strike Area	An administrative geographical boundary used for grouping resource accumulation.
Fractionation Plant	A processing facility that takes a natural gas liquids stream and separates out the component parts as specification products.
Frontier Gas	In this report this refers to gas produced from areas of northern and offshore Canada.

Gas	Raw gas, marketable gas, or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(j.1)).
Gas (Associated)	Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.
Gas (Marketable)	A mixture mainly of methane originating from raw gas or, if necessary, from the processing of the raw gas for the removal or partial removal of some constituents and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, Section 1(1)(m)).
Gas (Marketable at 101.325 kPa and 15°C)	The equivalent volume of marketable gas at standard conditions.
Gas (Nonassociated)	Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.
Gas (Raw)	A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these components that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(s.1)).
Gas (Solution)	Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.
Gas-Oil Ratio (Initial Solution)	The volume of gas (in cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.
Good Production Practice (GPP)	Production from oil pools at a rate (i) not governed by a base allowable, but (ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain its share of the production (*Oil and Gas Conservation Regulations* 1.020(2)9). This practice is authorized by the ERCB either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.

Gross Heating Value (of Dry Gas)	The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.
Horizontal Well	A well in which the lower part of the wellbore is drilled parallel to the zone of interest.
Initial Established Reserves	Established reserves prior to the deduction of any production.
Initial Volume in Place	The volume or mass of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in the ground before any quantity has been produced.
Maximum Day Rate	The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as maximum day rate.
Maximum Recoverable Thickness	The assumed maximum operational reach of underground coal mining equipment in a single seam.
Mean Formation Depth	The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.
Methane	In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide (*Oil and Gas Conservation Act*, Section 1(1)(m.1)).
Multilateral Well	A well where two or more production holes, usually horizontal in direction with reference to the zone of interest, are drilled from a single surface location.
Natural Gas Liquids	Ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.
Off-gas	Natural gas that is produced from bitumen upgrading to synthetic crude oil. This gas is typically rich in natural gas liquids and olefins.
Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(n.1)).

Oil Sands	(i) sands and other rock materials containing crude bitumen, (ii) the crude bitumen contained in those sands and other rock materials, and (iii) any other mineral substances other than natural gas in association with that crude bitumen or those sands and other rock materials referred to in subclauses (i) and (ii) (*Oil Sands Conservation Act*, Section 1(1)(o)).
Oil Sands Deposit	A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(o.1)).
Overburden	In this report overburden is a mining term related to the thickness of material above a mineable occurrence of coal or bitumen.
OPEC Reference Basket Price	OPEC calculates a production-weighted reference price, consisting of 12 different crudes: Saharan Blend (Algeria), Iran Heavy, Iraq Basra Light, Kuwait Export, Libya Es Sider, Bonny Light (Nigeria), Qatar Marine, Arab Light (Saudi Arabia), United Arab Emirates Murban, Merey (Venezuela), Girassol (Angola), and Oriente (Ecuador). The OPEC reference crude has an American Petroleum Institute (API) gravity of 32.7, with an average sulphur content of 1.77 per cent.
Pay Thickness (Average)	The bulk rock volume of a reservoir of oil, oil sands, or gas divided by its area.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate, or crude oil (*Oil and Gas Conservation Act*, Section 1(1)(p)).
Pool	A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(q)).
Porosity	The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.
Pressure (Initial)	The reservoir pressure at the reference elevation of a pool upon discovery.
Propane	In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes (*Oil and Gas Conservation Act*, Section 1(1)(s)).

Recovery (Enhanced)	The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool. The artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of (i) aiding in the lifting of fluids in the well, or (ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means (*Oil and Gas Conservation Act*, Section 1(1)(h)).
Recovery (Pool)	In gas pools, the fraction of the in-place reserves of gas expected to be recovered under the subsisting recovery mechanism.
Recovery (Primary)	Recovery of oil by natural depletion processes only measured as a volume thus recovered or as a fraction of the in-place oil.
Refined Petroleum Products	End products in the refining process.
Refinery Light Ends	Light oil products produced at a refinery; includes gasoline and aviation fuel.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reprocessing Facilities	Gas processing plants used to extract ethane and natural gas liquids from marketable natural gas. Such facilities, also referred to as straddle plants, are located on major natural gas transmission lines.
Reservoir	A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Retrograde Condensate Pools	Gas pools that have a dew point such that natural gas liquids will condense out of solution with a drop in reservoir pressure. To limit liquid dropout in the reservoir, dry gas is reinjected to maintain reservoir pressure.
Rich Gas	Natural gas that contains a relatively high concentration of natural gas liquids.
Sales Gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.

Saturation (Gas)	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Saturation (Water)	The fraction of pore space in the reservoir rock occupied by water upon discovery.
Shale Gas	The naturally occurring dry, predominantly methane gas produced from organic-rich, fine-grained rocks.
Shrinkage Factor (Initial)	The volume occupied by 1 cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.
Solvent	A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.
Specification Product	A crude oil or refined petroleum product with defined properties.
Sterilization	The rendering of otherwise definable economic ore as unrecoverable.
Straddle Plants	These are reprocessing plants on major natural gas transmission lines that process marketable gas by extracting natural gas liquids. This results in gas for export having a lower heat content than the marketable gas flowing within the province.
Strike Area	See Field/Strike Area.
Strip Ratio	The amount of overburden that must be removed to gain access to a unit amount of coal. A stripping ratio may be expressed as (1) thickness of overburden to thickness of coal, (2) volume of overburden to volume coal, (3) weight of overburden to weight of coal, or (4) cubic yards of overburden to tons of coal. A stripping ratio commonly is used to express the maximum thickness, volume, or weight of overburden that can be profitably removed to obtain a unit amount of coal.
Successful Wells Drilled	Wells drilled for gas or oil that are cased and not abandoned at the time of drilling.
Surface Loss	A summation of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons and is used as lease or plant fuel or is flared.

Synthetic Crude Oil	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands.
Temperature	The initial reservoir temperature upon discovery at the reference elevation of a pool.
Ultimate Potential	An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. Ultimate potential can be expressed by the following simple equation: Ultimate potential = initial established reserves + additions to existing pools + future discoveries.
Upgrading	The process that converts bitumen and heavy crude oil into a product with a density and viscosity similar to light crude oil.
Well Connections	Refers to the geological (producing) occurrences within a well; there may be more than one per wellbore.
Zone	Any stratum or sequence of strata that is designated by the ERCB as a zone (*Oil and Gas Conservation Act*, Section 1(1)(*z*)).

A.2 Abbreviations

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
DISC YEAR	discovery year
EOR	enhanced oil recovery
FRAC	fraction
GC	gas cycling
GIP	gas in place
GOR	gas-oil ratio
GPP	good production practice
INJ	Injected
I.S.	integrated scheme
KB	kelly bushing

LF	load factor
LOC EX PROJECT	local experimental project
LOC U	local utility
MB	material balance
MFD	mean formation depth
MOP	maximum operating pressure
MU	commingling order
NGL	natural gas liquids
NO	number
NON-ASSOC	nonassociated gas
PE	performance estimate
PD	production decline
RF	recovery factor
RGE	range
RPP	refined petroleum production
SA	strike area
SATN	saturation
SCO	synthetic crude oil
SF	solvent flood
SG	gas saturation
SL	surface loss
SOLN	solution gas
STP	standard temperature and pressure
SUSP	suspended
SW	water saturation
TEMP	temperature
TOT	total
TR	total record
TVD	true vertical depth
TWP	township
VO	volumetric reserve determination
VOL	volume
WF	waterflood

WM	west of [a certain] meridian
WTR DISP	water disposal
WTR INJ	water injection

A.3 Symbols

International System of Units (SI)

°C	degree Celsius	M	mega
d	day	m	metre
EJ	exajoule	MJ	megajoule
ha	hectare	mol	mole
J	joule	T	tera
kg	kilogram	t	tonne
kPa	kilopascal	TJ	terajoule

Imperial

bbl	barrel	°F	degree Fahrenheit
Btu	British thermal unit	psia	pounds per square inch absolute
cf	cubic foot	psig	pounds per square inch gauge
d	day		

A.4 Conversion Factors

Metric and Imperial Equivalent Units[a]

Metric	Imperial
1 m^3 of gas[b] (101.325 kPa and 15°C)	= 35.49373 cubic feet of gas
1 m^3 of ethane (equilibrium pressure and 15°C)	= 6.33 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	= 6.3000 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	= 6.2968 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	= 6.2929 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	= 6.2901 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	= 0.9842064 (U.K.) long tons (2240 pounds)
1 tonne	= 1.102311 short tons (2000 pounds)
1 kilojoule	= 0.9482133 British thermal units (Btu) as defined in the federal *Gas Inspection Act* (60-61°F)

[a] Reserves data in this report are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the imperial equivalents in the various tables.

[b] Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

Value and Scientific Notation

Term	Value	Scientific notation
kilo	thousand	10^3
mega	million	10^6
giga	billion	10^9
tera	thousand billion	10^{12}
peta	million billion	10^{15}
exa	billion billion	10^{18}

Energy Content Factors

Energy resource	Gigajoules
Natural gas (per thousand cubic metres)	37.4*
Ethane (per cubic metre)	18.5
Propane (per cubic metre)	25.4
Butanes (per cubic metre)	28.2
Oil (per cubic metre)	
Light and medium crude oil	38.5
Heavy crude oil	41.4
Bitumen	42.8
Synthetic crude oil	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Electricity (per megawatt-hour of output)	3.6

* Based on the heating value at 1000 Btu/cf.

Appendix B Summary of Crude Bitumen, Conventional Crude Oil, Natural Gas Reserves, and Natural Gas Liquids

Table B.1 Initial in-place resources of crude bitumen by deposit

Oil Sands Area Oil sands deposit	Depth/region/zone (m)	Resource determination method	Initial volume in place (10^6 m^3)
Athabasca			
Upper Grand Rapids	150–450+	Building block	5 274
Middle Grand Rapids	150–450+	Building block	2 354
Lower Grand Rapids	150–450+	Building block	1 050
Wabiskaw-McMurray	0–750+	Isopach	152 432
Nisku	200–800+	Isopach	10 330
Grosmont	All zones	Isopach	64 537
Subtotal			**235 977**
Cold Lake			
Upper Grand Rapids	All zones	Isopach	5 377
Lower Grand Rapids	All zones	Isopach	10 004
Clearwater	350–625	Isopach	9 422
Wabiskaw-McMurray	Northern	Isopach	2 161
Wabiskaw-McMurray	Central-southern	Building block	1 439
Wabiskaw-McMurray	Cummings & McMurray	Isopach	687
Subtotal			**29 090**
Peace River			
Bluesky-Gething	300–800+	Isopach	10 968
Belloy	675–700	Building block	282
Upper Debolt	500–800	Building block	1 830
Lower Debolt	500–800	Building block	5 970
Shunda	500–800	Building block	2 510
Subtotal			**21 560**
Total			**286 627**

Table B.2 Basic data of crude bitumen deposits

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Athabasca								
Upper Grand Rapids								
150–450+	Building Block	5 274.00	334.00	9.0	0.062	0.55	0.30	0.45
Middle Grand Rapids								
150–450+	Building Block	2 354.00	182.00	5.0	0.077	0.68	0.30	0.32
Lower Grand Rapids								
150–450+	Building Block	1 050.00	173.00	6.0	0.051	0.45	0.30	0.55
Wabiskaw-McMurray								
0–65 (mineable)	Isopach	20 823.00	375.00	25.9	0.101	0.76	0.28	0.24
65–750+ (in situ)	Isopach	131 609.00	4 694.00	13.1	0.102	0.73	0.29	0.27
Nisku								
200–800+	Isopach	10 330.00	499.00	8.0	0.057	0.63	0.21	0.37
Grosmont								
D	Isopach	32 860.00	850.00	21.0	0.081	0.81	0.23	0.19
C	Isopach	18 755.00	1 069.00	13.6	0.054	0.78	0.17	0.22
B	Isopach	4 450.00	787.00	4.9	0.048	0.76	0.15	0.24
A	Isopach	8 472.00	1 274.00	6.5	0.041	0.72	0.14	0.28
Cold Lake								
Upper Grand Rapids								
All Zones	Total Isopach	5 377.00	612.00	4.8	0.090	0.65	0.28	0.35
Colony 1								
Lindbergh C	Isopach	0.18	0.05	1.5	0.115	0.79	0.31	0.21
Beaverdam A	Isopach	7.33	1.05	2.9	0.115	0.79	0.31	0.21
Beaverdam B	Isopach	4.75	0.52	3.5	0.122	0.84	0.31	0.16
Beaverdam C	Isopach	2.03	0.26	3.1	0.119	0.76	0.33	0.24
Beaverdam/ Bonnyville A	Isopach	12.11	1.90	2.6	0.116	0.80	0.31	0.20
Colony 2								
Frog Lake A	Isopach	2.01	0.47	1.8	0.109	0.75	0.31	0.25
Frog Lake B	Isopach	0.11	0.04	1.3	0.093	0.67	0.30	0.33
Frog Lake C	Isopach	0.35	0.12	1.3	0.103	0.74	0.30	0.26
Frog Lake D	Isopach	0.29	0.10	1.3	0.099	0.71	0.30	0.29
Frog Lake E	Isopach	0.43	0.13	1.4	0.106	0.79	0.29	0.21
Frog Lake F	Isopach	0.33	0.10	1.7	0.092	0.69	0.29	0.31
Frog Lake M	Isopach	0.55	0.14	1.8	0.100	0.72	0.30	0.28
Frog Lake N	Isopach	0.80	0.25	1.5	0.099	0.71	0.30	0.29
Frog Lake O	Isopach	0.15	0.03	2.5	0.096	0.66	0.31	0.34
Lindbergh A	Isopach	0.83	0.26	1.6	0.091	0.68	0.29	0.32
Lindbergh D	Isopach	1.20	0.13	3.4	0.130	0.86	0.32	0.14
Lindbergh E	Isopach	6.11	0.39	5.3	0.139	0.92	0.32	0.08
Lindbergh F	Isopach	0.85	0.09	3.3	0.136	0.90	0.32	0.10
Lindbergh G	Isopach	2.35	0.33	2.7	0.124	0.82	0.32	0.18
Lindbergh J	Isopach	3.56	0.60	2.6	0.106	0.76	0.30	0.24
Lindbergh K	Isopach	6.23	0.92	3.0	0.107	0.74	0.31	0.26
Lindbergh L	Isopach	1.99	0.31	2.4	0.125	0.83	0.32	0.17
Colony 3								
Frog Lake G	Isopach	0.48	0.09	2.1	0.116	0.83	0.30	0.17

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place ($10^6 m^3$)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/ Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/ Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
All Zones	Total Isopach	1 004.00	658.00	7.8	0.092	0.65	0.30	0.35
Sparky								
Frog Lake A	Isopach	4.60	0.75	2.9	0.100	0.69	0.31	0.31
Frog Lake B	Isopach	0.30	0.06	2.2	0.109	0.72	0.32	0.28
Frog Lake C	Isopach	0.79	0.16	2.2	0.107	0.74	0.31	0.26
Frog Lake D	Isopach	0.21	0.07	1.7	0.083	0.62	0.29	0.38
Frog Lake E	Isopach	1.54	0.31	2.6	0.087	0.65	0.29	0.35
Frog Lake F	Isopach	12.36	1.47	3.1	0.130	0.83	0.33	0.17
Frog Lake G	Isopach	0.51	0.06	3.2	0.123	0.85	0.31	0.15
Frog Lake H	Isopach	0.09	0.02	1.7	0.127	0.81	0.33	0.19
Frog Lake I	Isopach	5.72	0.74	2.6	0.144	0.85	0.35	0.15
Lindbergh A	Isopach	54.96	8.17	3.1	0.102	0.70	0.31	0.30
Lindbergh C	Isopach	0.91	0.37	1.4	0.084	0.60	0.30	0.40
Lindbergh D	Isopach	26.51	4.05	2.7	0.116	0.74	0.33	0.26
Lindbergh E	Isopach	0.12	0.09	0.8	0.078	0.67	0.26	0.33
Lindbergh F	Isopach	0.31	0.14	1.3	0.081	0.58	0.30	0.42

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh I	Isopach	0.13	0.07	0.9	0.100	0.64	0.33	0.36
Lindbergh K	Isopach	0.84	0.24	1.7	0.093	0.67	0.30	0.33
Lindbergh L	Isopach	3.45	0.58	2.1	0.140	0.83	0.34	0.17
Lindbergh M	Isopach	7.10	0.85	3.1	0.130	0.83	0.33	0.17
Beaverdam A	Isopach	3.90	0.30	5.2	0.119	0.73	0.34	0.27
Beaverdam B	Isopach	3.40	0.33	4.8	0.103	0.63	0.34	0.37
Beaverdam C	Isopach	6.53	0.79	3.0	0.130	0.80	0.34	0.20
Beaverdam D	Isopach	30.23	3.48	3.3	0.124	0.82	0.32	0.18
Beaverdam E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23
Mann Lake/ Seibert Lk A	Isopach	6.61	0.55	4.4	0.129	0.82	0.33	0.18
Lower Grand Rapids 2								
Frog Lake OO	Isopach	1.71	0.27	2.9	0.103	0.74	0.30	0.26
Frog Lake QQ	Isopach	0.55	0.10	2.2	0.119	0.82	0.31	0.18
Lindbergh G	Isopach	35.32	5.94	2.8	0.100	0.69	0.31	0.31
Lindbergh K	Isopach	0.76	0.21	2.0	0.084	0.63	0.29	0.37
Lindbergh VV	Isopach	0.36	0.12	1.5	0.095	0.68	0.30	0.32
Lindbergh WW	Isopach	2.60	0.51	2.0	0.122	0.78	0.33	0.22
Beaverdam A	Isopach	4.66	1.67	1.8	0.069	0.62	0.25	0.38
Cold Lake A	Isopach	3.09	0.89	1.5	0.111	0.71	0.33	0.29
Cold Lake D	Isopach	0.58	0.19	1.2	0.122	0.75	0.34	0.25
Lower Grand Rapids 3								
Frog Lake C	Isopach	4.80	0.46	4.4	0.112	0.77	0.31	0.23
Frog Lake D	Isopach	10.38	1.09	3.7	0.121	0.80	0.32	0.20
Frog Lake E	Isopach	4.50	0.88	2.3	0.106	0.73	0.31	0.27
Frog Lake F	Isopach	0.41	0.10	1.9	0.098	0.73	0.29	0.27
Lindbergh F	Isopach	31.58	3.02	4.2	0.118	0.78	0.32	0.22
Lindbergh L	Isopach	1.58	0.24	2.9	0.108	0.69	0.33	0.31
Lindbergh M	Isopach	8.40	1.46	2.7	0.100	0.69	0.31	0.31
Lindbergh O	Isopach	11.50	1.54	3.7	0.095	0.68	0.30	0.32
Lindbergh P	Isopach	2.04	0.25	3.5	0.110	0.76	0.31	0.24
Lindbergh Q	Isopach	27.61	2.92	3.7	0.119	0.79	0.32	0.21
Lindbergh S	Isopach	2.46	0.37	2.8	0.113	0.72	0.33	0.28
Lindbergh T	Isopach	2.97	0.47	2.6	0.115	0.76	0.32	0.24
Lindbergh U	Isopach	0.18	0.06	1.4	0.094	0.70	0.29	0.30
Lindbergh V	Isopach	0.13	0.06	1.3	0.081	0.56	0.31	0.44
Lindbergh X	Isopach	0.75	0.20	2.4	0.073	0.57	0.28	0.43
Lindbergh Y	Isopach	1.61	0.35	2.5	0.086	0.59	0.31	0.41
Lindbergh Z	Isopach	0.12	0.07	0.8	0.094	0.65	0.31	0.35
Lindbergh AA	Isopach	3.26	0.50	3.1	0.099	0.71	0.30	0.29
Lindbergh BB	Isopach	0.08	0.03	1.4	0.093	0.59	0.33	0.41
Lindbergh CC	Isopach	2.18	0.31	3.0	0.110	0.76	0.31	0.24
Lindbergh OO	Isopach	0.24	0.09	1.6	0.075	0.54	0.30	0.46
Lindbergh XX	Isopach	0.32	0.09	1.9	0.086	0.62	0.30	0.38

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation		Porosity (fraction)	Water saturation (fraction)
					(mass fraction)	(pore volume fraction)		
Lindbergh YY	Isopach	3.94	0.39	4.0	0.117	0.81	0.31	0.19
Frog Lake/ Lindbergh C	Isopach	9.95	1.07	3.7	0.119	0.79	0.32	0.21
Frog Lake/ Beaverdam A	Isopach	3.85	0.55	2.8	0.119	0.73	0.34	0.27
Lindbergh/ St. Paul A	Isopach	9.58	0.81	4.6	0.121	0.80	0.32	0.20
Beaverdam B	Isopach	84.40	9.49	3.5	0.121	0.77	0.33	0.23
Beaverdam G	Isopach	1.46	0.25	2.4	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	1.65	0.31	2.1	0.120	0.74	0.34	0.26
Cold Lake B	Isopach	2.73	0.56	2.0	0.116	0.71	0.34	0.29
Wolf Lake D	Isopach	23.34	2.64	3.1	0.139	0.82	0.35	0.18
Lower Grd Rap Channel Sd								
Beaverdam F	Isopach	26.72	0.86	10.4	0.145	0.83	0.36	0.17
Wolf Lake F	Isopach	101.14	3.39	10.3	0.140	0.83	0.35	0.17
Lower Grand Rapids 4								
Frog Lake G	Isopach	9.15	0.97	3.6	0.124	0.79	0.33	0.21
Frog Lake I	Isopach	15.37	1.52	4.0	0.121	0.80	0.32	0.20
Frog Lake J	Isopach	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake NN	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28
Frog Lake PP	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh DD	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh EE	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh FF	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh GG	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh HH	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh II	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh JJ	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh KK	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh MM	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh NN	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh PP	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29
Lindbergh QQ	Isopach	0.79	0.14	2.4	0.107	0.80	0.29	0.20

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation		Porosity (fraction)	Water saturation (fraction)
					(mass fraction)	(pore volume fraction)		
Lindbergh RR	Isopach	0.05	0.02	1.4	0.089	0.64	0.30	0.36
Lindbergh SS	Isopach	3.12	0.29	4.7	0.110	0.70	0.33	0.30
Lindbergh UU	Isopach	0.57	0.10	2.4	0.113	0.75	0.32	0.25
Lindbergh ZZ	Isopach	10.13	1.10	3.8	0.113	0.78	0.31	0.22
Lindbergh EEE	Isopach	0.56	0.05	4.2	0.129	0.82	0.33	0.18
Lindbergh FFF	Isopach	3.81	0.54	2.7	0.127	0.80	0.33	0.20
Lindbergh GGG	Isopach	1.42	0.22	2.4	0.129	0.81	0.33	0.19
Lindbergh HHH	Isopach	2.21	0.27	3.0	0.129	0.82	0.33	0.18
Lindbergh JJJ	Isopach	2.20	0.27	3.0	0.127	0.84	0.32	0.16
Beaverdam C	Isopach	24.01	2.69	3.5	0.119	0.79	0.32	0.21
Cold Lake C	Isopach	4.22	0.77	2.2	0.117	0.72	0.34	0.28
Lindbergh/ St. Paul B	Isopach	9.63	1.22	3.4	0.110	0.73	0.32	0.27
Lower Grand Rapids 5								
Lindbergh AAA	Isopach	2.51	0.40	3.1	0.093	0.70	0.29	0.30
Lindbergh BBB	Isopach	0.29	0.10	1.6	0.083	0.62	0.29	0.38
Lindbergh CCC	Isopach	0.11	0.04	1.6	0.080	0.60	0.29	0.40
St. Paul A	Isopach	1.93	0.32	3.1	0.089	0.64	0.30	0.36
St. Paul B	Isopach	0.24	0.06	2.2	0.084	0.63	0.29	0.37
Lloydminster								
Frog Lake A	Isopach	1.34	0.17	3.9	0.097	0.62	0.33	0.38
Frog Lake B	Isopach	4.63	0.54	4.4	0.091	0.63	0.31	0.37
Frog Lake C	Isopach	2.85	0.38	3.6	0.100	0.64	0.33	0.36
Lindbergh D	Isopach	3.65	0.54	2.8	0.116	0.74	0.33	0.26
Lindbergh F	Isopach	2.91	0.48	3.6	0.078	0.56	0.30	0.44
Lindbergh G	Isopach	1.01	0.14	4.0	0.085	0.61	0.30	0.39
Lindbergh H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/ Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37
Lindbergh/ St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/ St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/ Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./ Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350–625	Isopach	9 422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2 161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1 439.00	285.00	4.1	0.057	0.51	0.25	0.49
Cummings 1								
Frog Lake A	Isopach	4.07	0.69	2.4	0.116	0.83	0.30	0.17
Frog Lake B	Isopach	1.52	0.17	3.4	0.124	0.82	0.32	0.18

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation		Porosity (fraction)	Water saturation (fraction)
					(mass fraction)	(pore volume fraction)		
Frog Lake C	Isopach	5.20	0.66	3.0	0.122	0.81	0.32	0.19
Frog Lake/ Lindbergh A	Isopach	38.28	3.76	3.9	0.122	0.84	0.31	0.16
Lindbergh/ St. Paul A	Isopach	273.08	29.62	3.9	0.109	0.78	0.30	0.22
Cummings 2								
St. Paul B	Isopach	1.32	0.18	3.2	0.106	0.76	0.30	0.24
Lindbergh/ St. Paul B	Isopach	221.36	20.89	4.2	0.117	0.81	0.31	0.19
McMurray								
Lindbergh A	Isopach	89.87	5.49	6.1	0.127	0.84	0.32	0.16
Lindbergh B	Isopach	0.09	0.02	2.4	0.083	0.68	0.27	0.32
Lindbergh C	Isopach	42.72	5.83	3.1	0.112	0.77	0.31	0.23
Lindbergh D	Isopach	0.94	0.11	3.2	0.125	0.86	0.31	0.14
Lindbergh E	Isopach	0.07	0.05	0.7	0.088	0.69	0.28	0.31
Lindbergh F	Isopach	8.11	0.55	6.7	0.103	0.71	0.31	0.29
St. Paul A	Isopach	0.04	0.02	1.2	0.090	0.62	0.31	0.38
Peace River								
Bluesky-Gething								
300–800+	Isopach	10 968.00	1 016.00	6.1	0.081	0.68	0.26	0.32
Belloy								
675–700	Building Block	282.00	26.00	8.0	0.078	0.64	0.27	0.36
Upper Debolt								
500–800	Building Block	1 830.00	100.00	13.0	0.050	0.61	0.19	0.39
Lower Debolt								
500–800	Building Block	5 970.00	202.00	29.0	0.051	0.67	0.18	0.33
Shunda								
500–800	Building Block	2 510.00	143.00	14.0	0.053	0.52	0.23	0.48
Total		**286 626.67**						

Table B.3 Conventional crude oil reserves as of each year-end (10^6 m^3)

	Initial established						
Year	New discoveries	EOR additions	Development	Net revisions	Net total additions	Cumulative production	Remaining established
1968	62.0				119.8	430.3	1 212.8
1969	40.5				54.5	474.7	1 222.8
1970	8.4				36.7	526.5	1 207.9
1971	14.0				22.1	582.9	1 173.6
1972	10.8				20.0	650.0	1 126.0
1973	5.1				9.2	733.7	1 052.0
1974	4.3				38.5	812.7	1 011.5
1975	1.6				7.0	880.2	950.9
1976	2.5				-18.6	941.2	871.3
1977	4.8				19.1	1 001.6	830.0
1978	24.9				24.4	1 061.6	794.5
1979	19.2				34.3	1 130.1	760.2
1980	9.0				22.8	1 193.3	719.9
1981	15.0	7.2			32.6	1 249.8	696.0
1982	16.8	6.6			6.9	1 303.4	649.4
1983	21.4	17.9			64.1	1 359.0	657.8
1984	29.1	24.1			42.0	1 418.2	640.7
1985	32.7	21.6			64.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2 304.7	278.3
2002	7.0	0.6	8.1	4.6	20.2	2 343.0	260.3
2003	6.9	1.0	5.9	17.1	30.8	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2 480.7	250.1
2007	6.8	2.2	11.8	-0.2	20.6	2 510.9	240.7
2008	6.9	6.2	9.3	-0.7	21.7	2 540.1	233.0
2009	4.0	4.8	7.4	+5.8	21.8	2 566.5	228.4
2010	3.8	5.8	23.5	+1.7	34.8	2592.8	236.9

Table B.4 Summary of marketable natural gas reserves as of each year-end (10^9 m^3)

	Initial established							
Year	New discoveries	Development	Revisions	Net additions	Cumulative	Cumulative production	Remaining actual[a]	Remaining @ 37.4 MJ/m^3
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	89.4	53.8	-56.0	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	55.5	64.5	25.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	40.4	49.9	35.0	125.7	4 672.4	3 552.4	1 120.0	1 164.0

(continued)

Table B.4 Summary of marketable natural gas reserves as of each year-end (10^9 m^3) (continued)

	Initial established							
Year	New discoveries	Development	Revisions	Net additions	Cummulative	Cumulative production	Remaining actual[a]	Remaining @ 37.4 MJ/m^3
2006	83.4	48.4	-5.4	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007	71.0	30.0	-6.4	94.6	4 893.3	3 823.9	1 069.3	1 112.2
2008	69.3	31.3	54.8	155.4	5 048.7	3 950.5	1 098.2	1 142.3
2009	43.1	20.1	18.8	82.0	5 130.7	4 075.0	1 055.7	1 098.0
2010	24.3	25.3	33.2	82.8	5 213.5	4 188.4	1 025.1	1 065.7

[a] At field plant

Table B.5 Natural gas reserves of gas cycling pools, 2010

Pool	Raw gas initial volume in place (10^6 m^3)	Raw gas gross heating value (MJ/m^3)	Initial energy in place (10^9 MJ)	Recovery factor (fraction)	Fuel and shrinkage (surface loss factor) (fraction)	Initial marketable gas energy (10^9 MJ)	Marketable gas gross heating value (MJ/m^3)	Initial established reserves of marketable gas (10^6 m^3)	Remaining established reserves of marketable gas (10^6 m^3)
Brazeau River Nisku K	1 063	74.17	79	0.90	0.22	31	42.15	746	32
Brazeau River Nisku M	1 621	76.22	124	0.90	0.26	45	41.36	1 080	51
Brazeau River Nisku P	8 660	61.23	530	0.72	0.46	139	40.45	3 445	787
Brazeau River Nisku AA	484	55.65	27	0.63	0.30	9	41.11	214	6
Caroline Beaverhill Lake A	60 892	49.95	3 042	0.62	0.55	617	36.51	16 989	1 072
Carson Creek Beaverhill Lake B	11 919	55.68	664	0.90	0.18	361	41.06	8 796	315
Harmattan East Commingled Pool 001	39 372	50.26	1 979	0.85	0.26	1 218	40.43	30 119	5 577
Harmattan-Elkton Rundle C	26 436	46.96	1 241	0.93	0.15	867	41.48	20 897	726
Kakwa A Cardium A	3 848	55.40	213	0.71	0.32	97	41.13	2 348	1 034
Kaybob South Beaverhill Lake A	110 446	52.61	5 811	0.72	0.48	1 641	39.68	41 351	368
Ricinus Cardium A	13 295	58.59	779	0.90	0.10	437	40.52	10 789	370
Valhalla MFP8524 Halfway	6 331	53.89	341	0.80	0.10	182	40.00	4 559	2 328
Waterton Rundle-Wabamun A	90 422	48.74[a]	4 407	0.95	0.35	2 190	39.22	55 836	1 824
Wembley MFP8524 Halfway	6 662	53.89	359	0.60	0.18	131	40.00	3 265	1 737

Table B.6 Natural gas reserves of multifield pools, 2010

Multifield pool Field and pool	Remaining established reserves ($10^6 m^3$)
MFP8515 Banff	
Haro MFP8515 Banff	112
Rainbow MFP8515 Banff	6
Rainbow South MFP8515 Banff	191
Total	309
MFP8516 Viking	
Fenn West MFP8516 Viking	8
Fenn-Big Valley MFP8516 Viking	52
Total	60
MFP8524 Halfway	
Valhalla MFP8524 Halfway	2 328
Wembley MFP8524 Halfway	1 737
Total	4 065
MFP8525 Colony	
Ukalta MFP8525 Colony	0
Whitford MFP8525 Colony	0
Total	0
MFP8528 Bluesky	
Rainbow MFP8528 Bluesky	138
Sousa MFP8528 Bluesky	562
Total	700
MFP8529 Bluesky-Detrital-Debolt	
Cranberry MFP8529 BL-DT-DB	422
Hotchkiss MFP8529 BL-DT-DB	428
Total	850
MFP8541 Second White Specks	
Cherry MFP8541 2WS	27
Granlea MFP8541 2WS	42
Taber MFP8541 2WS	125
Total	194
MFP8589 Edmonton	
Delia MFP8589 Edmonton	16
Rowley MFP8589 Edmonton	20
Total	36
MFP8591 Basal Belly River	
Little Bow MFP8591 Bsl Belly River	5
Retlaw MFP8591 Bsl Belly River	49
Total	54
Commingled MFP9502	
Ansell Commingled MFP9502	15 282
Medicine Lodge Commingled MFP9502	1 479
Minehead Commingled MFP9502	1 483
Sundance Commingled MFP9502	9 649
Total	27 893
Commingled MFP9503	
Hairy Hill Commingled MFP9503	248
Willingdon Commingled MFP9503	11
Total	259
Commingled MFP9504	
Alix Commingled MFP9504	725
Bashaw Commingled MFP9504	2 545
Buffalo Lake Commingled MFP9504	16
Chigwell Commingled MFP9504	109
Chigwell North Commingled MFP9504	241
Clive Commingled MFP9504	458
Donalda Commingled MFP9504	109
Dorenlee Commingled MFP9504	5
Ferintosh Commingled MFP9504	72
Haynes Commingled MFP9504	1
Lacombe Commingled MFP9504	17
Malmo Commingled MFP9504	466
Nevis Commingled MFP9504	1 565
Wood River Commingled MFP9504	113
Total	6 442
Commingled MFP9505	
Bigoray Commingled MFP9505	207
Pembina Commingled MFP9505	809
Total	147
Commingled MFP9506	
Bonnie Glen Commingled MFP9506	57
Ferrybank Commingled MFP9506	204
Total	261
Commingled MFP9508	
Fairydell-Bon Accord Commingled MFP9508	49
Peavey Commingled MFP9508	1
Redwater Commingled MFP9508	529
Total	579
Commingled MFP9509	
Albers Commingled MFP9509	7
Beaverhill Lake Commingled MFP9509	277
Bellshill Lake Commingled MFP9509	11
Birch Commingled MFP9509	7
Bruce Commingled MFP9509	349
Dinant Commingled MFP9509	2
Edberg Commingled MFP9509	0
Fort Saskatchewan Commingled MFP9509	178
Holmberg Commingled MFP9509	175
Kelsey Commingled MFP9509	100
Killam Commingled MFP9509	136
Killam North Commingled MFP9509	92
Mannville Commingled MFP9509	412
Sedgewick Commingled MFP9509	9
Viking-Kinsella Commingled MFP9509	1 981
Wainwright Commingled MFP9514	369
Total	4 105
Commingled MFP9510	
Fox Creek Commingled MFP9510	1 091
Kaybob South Commingled MFP9510	884
Total	1 975
Commingled MFP9511	
Hudson Commingled MFP9511	28
Sedalia Commingled MFP9511	225
Total	253
Commingled MFP9512	
Inland Commingled MFP9512	139
Royal Commingled MFP9512	0
Total	139
Commingled MFP9513	
Elmworth Commingled MFP9513	14 876
Sinclair Commingled MFP9513	4 270
Total	19 146
Commingled MFP9514	
Connorsville Commingled MFP9514	615
Wintering Hills Commingled MFP9514	240
Total	855

(continued)

Table B.6 Natural gas reserves of multifield pools, 2010 (continued)

Multifield pool Field and pool	Remaining established reserves ($10^6 m^3$)
Commingled MFP9515	
Craigmyle Commingled MFP9515	7
Dowling Lake Commingled MFP9515	11
Garden Plains Commingled MFP9515	854
Hanna Commingled MFP9515	401
Provost Commingled MFP9515	175
Racosta Commingled MFP9515	88
Richdale Commingled MFP9515	342
Stanmore Commingled MFP9515	29
Sullivan Lake Commingled MFP9515	60
Watts Commingled MFP9515	50
Total	2 017
Commingled MFP9516	
Knopcik Commingled MFP9516	618
Valhalla Commingled MFP9516	27
Total	645
Commingled MFP9517	
Conrad Commingled MFP9517	70
Pendant D'Oreille Commingled MFP9517	1549
Smith Coulee Commingled MFP9517	319
Total	1 938
Commingled MFP9520	
Gadsby Commingled MFP9520	41
Leahurst Commingled MFP9520	96
Total	137
Commingled MFP9522	
Enchant Commingled MFP9522	483
Grand Forks Commingled MFP9522	9
Retlaw Commingled MFP9522	109
Vauxhall Commingled MFP9522	28
Total	629
Commingled MFP9524	
Stirling Commingled MFP9524	99
Warner Commingled MFP9524	24
Total	123
Commingled MFP9525	
Resthaven Commingled MFP9525	1 053
Smoky Commingled MFP9525	220
Total	1 273
Commingled MFP9526	
Garrington Commingled MFP9526	8
Innisfail Commingled MFP9526	23
Lanaway Commingled MFP9526	399
Markerville Commingled MFP9526	210
Medicine River Commingled MFP9526	147
Penhold Commingled MFP9526	6
Sylvan Lake Commingled MFP9526	371
Tindastoll Commingled MFP9526	82
Willesden Green Commingled MFP9526	5
Total	2 251
Commingled MFP9527	
Crystal Commingled MFP9527	149
Gilby Commingled MFP9527	17
Minnehik-Buck Lake Commingled MFP9527	142
Westerose South Commingled MFP9527	280
Wilson Creek Commingled MFP9527	383
Total	971
Commingled MFP9528	
Comrey Commingled MFP9528	26
Forty Mile Commingled MFP9528	61
Pendant D'Oreille Commingled MFP9528	666
Smith Coulee Commingled MFP9528	10
Total	763
Commingled MFP9529	
Berland River Commingled MFP9529	10
Berland River West Commingled MFP9529	47
Cecilia Commingled MFP9529	6 884
Elmworth Commingled MFP9529	1 224
Fir Commingled MFP9529	9 072
Kaybob South Commingled MFP9529	3 367
Oldman Commingled MFP9529	1 685
Red Rock Commingled MFP9529	5 738
Wapiti Commingled MFP9529	20 600
Wild River Commingled MFP9529	23 854
Wild Hay Commingled MFP9529	878
Total	73 359
Commingled MFP9530	
Gilby Commingled MFP9530	237
Prevo Commingled MFP9530	57
Total	294
Commingled MFP9531	
Nosehill Commingled MFP9531	611
Pine Creek Commingled MFP9531	1 066
Total	1677
Commingled MFP9531	
Nosehill Commingled MFP9531	611
Pine Creek Commingled MFP9531	1 066
Total	1 677
Commingled MFP9532	
Grizzly Commingled MFP9532	211
Waskahigan Commingled MFP9532	61
Total	272
Commingled MFP9533	
Bigstone Commingled MFP9533	188
Placid Commingled MFP9533	668
Total	856
Commingled MFP9534	
Jenner Commingled MFP9534	9
Princess Commingled MFP9534	10
Total	19
Commingled MFP9535	
Carrot Creek Commingled MFP9535	413
Pembina Commingled MFP9535	300
Total	713
Commingled MFP9536	
Chinook Commingled MFP9536	128
Dobson Commingled MFP9536	16
Heathdale Commingled MFP9536	32
Kirkwall Commingled MFP9536	11
Sedalia Commingled MFP9536	106
Sounding Commingled MFP9536	91
Stanmore Commingled MFP9536	74
Total	458

(continued)

Table B.6 Natural gas reserves of multifield pools, 2010 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9501 (Southeast Alberta Gas System)	
Aerial Commingled MFP9501	128
Alderson Commingled MFP9501	16 902
Armada Commingled MFP9501	200
Atlee-Buffalo Commingled MFP9501	3 628
Badger Commingled MFP9501	45
Bantry Commingled MFP9501	14 402
Berry Commingled MFP9501	4
Bindloss Commingled MFP9501	748
Blackfoot Commingled MFP9501	498
Bow Island Commingled MFP9501	352
Brooks Commingled MFP9501	350
Carbon Commingled MFP9501	861
Cavalier Commingled MFP9501	611
Cessford Commingled MFP9501	6 427
Chain Commingled MFP9501	245
Chauncey Commingled MFP9501	127
Connemara Commingled MFP9501	5
Connorsville Commingled MFP9501	1 332
Countess Commingled MFP9501	36 979
Craigmyle Commingled MFP9501	593
Crossfield Commingled MFP9501	97
Davey Commingled MFP9501	328
Delia Commingled MFP9501	389
Drumheller Commingled MFP9501	2 148
Elkwater Commingled MFP9501	1 056
Elnora Commingled MFP9501	320
Enchant Commingled MFP9501	99
Entice Commingled MFP9501	8 763
Erskine Commingled MFP9501	32
Ewing Lake Commingled MFP9501	66
Eyremore Commingled MFP9501	2 386
Fenn West Commingled MFP9501	110
Fenn-Big Valley Commingled MFP9501	1 441
Gadsby Commingled MFP9501	391
Gartley Commingled MFP9501	23
Ghost Pine Commingled MFP9501	804
Gleichen Commingled MFP9501	410
Hector Commingled MFP9501	2
Herronton Commingled MFP9501	1 514
High River Commingled MFP9501	17
Hussar Commingled MFP9501	5 087
Huxley Commingled MFP9501	394
Jenner Commingled MFP9501	2 157
Joffre Commingled MFP9501	6
Johnson Commingled MFP9501	286
Jumpbush Commingled MFP9501	525
Kitsim Commingled MFP9501	154
Lathom Commingled MFP9501	2 253
Leckie Commingled MFP9501	726
Leo Commingled MFP9501	290
Little Bow Commingled MFP9501	28
Lomond Commingled MFP9501	79
Lone Pine Creek Commingled MFP9501	251
Long Coulee Commingled MFP9501	219
Majorville Commingled MFP9501	909
Matziwin Commingled MFP9501	1 048
Mcgregor Commingled MFP9501	193
Medicine Hat Commingled MFP9501	45 997
Michichi Commingled MFP9501	351
Milo Commingled MFP9501	38
Newell Commingled MFP9501	803
Okotoks Commingled MFP9501	175
Pageant Commingled MFP9501	6
Parflesh Commingled MFP9501	1 014
PenholdCommingled MFP9501	12
Pollockville Commingled MFP9501	1
Princess Commingled MFP9501	9 308
Queenstown Commingled MFP9501	245
Rainier Commingled MFP9501	77
Redland Commingled MFP9501	895
Rich Commingled MFP9501	163
Rockyford Commingled MFP9501	1 928
Ronalane Commingled MFP9501	73
Rowley Commingled MFP9501	542
Rumsey Commingled MFP9501	179
Seiu Lake Commingled MFP9501	282
Shouldice Commingled MFP9501	733
Silver Commingled MFP9501	26
Stettler Commingled MFP9501	132
Stettler North Commingled MFP9501	36
Stewart Commingled MFP9501	678
Suffield Commingled MFP9501	15 604
Swalwell Commingled MFP9501	484
Three Hills Creek Commingled MFP9501	850
Trochu Commingled MFP9501	544
Twining Commingled MFP9501	752
Verger Commingled MFP9501	6 756
Vulcan Commingled MFP9501	134
WattsCommingled MFP9501	10
Wayne-Rosedale Commingled MFP9501	4 677
West Drumheller Commingled MFP9501	64
Wimborne Commingled MFP9501	888
Wintering Hills Commingled MFP9501	3 600
Workman Commingled MFP9501	194
Total	218 213

Table B.7 Remaining raw ethane reserves as of December 31, 2010

Field	Remaining reserves of marketable gas ($10^6 m^3$)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas ($10^6 m^3$)	Liquid ($10^3 m^3$)
Ansell	17 324	0.082	1 560	5 546
Brazeau River	9 741	0.074	887	3 152
Caroline	7 331	0.086	889	3 159
Cecilia	7 540	0.062	522	1 857
Countess	39 738	0.011	463	1 647
Dunvegan	7 627	0.044	369	1 311
Edson	6 968	0.076	593	2 109
Elmworth	20 722	0.059	1 440	5 118
Ferrier	10 257	0.086	990	3 520
Fir	10 337	0.057	649	2 308
Garrington	3 151	0.076	311	1 105
Gilby	5 130	0.066	386	1 372
Gold Creek	5 829	0.079	507	1 801
Harmattan East	6 807	0.085	656	2 332
Judy Creek	2 333	0.140	398	1 415
Kaybob South	15 833	0.070	1 290	4 585
Karr	4 147	0.075	347	1 232
Kakwa	7 596	0.084	718	2 552
Leduc-Woodbend	2 316	0.114	309	1 100
Medicine River	3 615	0.088	388	1 380
Obed	4 785	0.064	338	1 202
Pembina	23 361	0.078	2 453	8 720
Pine Creek	7 658	0.071	626	2 225
Pouce Coupe South	7 797	0.048	421	1 495
Provost	11 579	0.031	403	1 434
Rainbow	6 976	0.069	608	2 162
Rainbow South	2 884	0.093	385	1 370
Red Rock	7 672	0.059	506	1 798
Ricinus	4 069	0.073	336	1 195
Sinclair	8 845	0.051	515	1 831
Sundance	11 403	0.069	869	3 089
Swan Hills South	2 654	0.174	660	2 348
Sylvan Lake	3 413	0.082	333	1 183
Valhalla	7 366	0.076	646	2 298
Virginia Hills	1 385	0.173	295	1 047
Westpem	4 260	0.103	540	1 920
Westerose South	6 523	0.081	589	2 094
Wembley	2 571	0.095	307	1 093
Wapiti	25 338	0.055	1 614	5 739
Wild River	26 388	0.071	2 037	7 240
Willesden Green	11 983	0.086	1 264	4 492
Subtotal	**383 252**	**0.066**	**29 415**	**104 574**
All other fields	**641 843**	**0.030**	**21 528**	**68 868**
Total	**1 025 095**	**0.052**[a]	**50 942**	**173 442**

[a] Volume weighted average.

Table B.6 Remaining raw reserves of natural gas liquids as of December 31, 2010

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ansell	17 324	2 507	1 319	2 748	6 574
Brazeau River	9 741	1 512	886	1 919	4 318
Caroline	7 331	1 325	845	1 572	3 741
Cecilia	7 540	586	246	795	1 627
Countess	39 738	622	316	303	1 271
Dunvegan	7 627	630	364	601	1 595
Edson	6 968	781	362	357	1 500
Elmworth	20 722	1 611	731	825	3 168
Ferrier	10 257	1 734	872	864	3 470
Fir	10 337	879	424	573	1 875
Garrington	3 151	497	264	360	1 120
Gilby	5 130	672	345	371	1 388
Gold Creek	5 829	597	295	420	1 313
Harmattan East	6 807	886	552	923	2 361
Hussar	7 777	428	231	234	893
Judy Creek	2 333	951	395	232	1 578
Kakwa	7 596	1 108	518	571	2 196
Karr	4 147	530	240	243	1 013
Kaybob	2 752	395	189	263	847
Kaybob South	15 833	2 048	1 061	1 400	4 510
Leduc-Woodbend	2 316	925	547	328	1 800
Medicine River	3 615	639	315	307	1 261
Pembina	23 361	5 006	2 471	1 897	9 374
Pine Creek	7 658	895	414	476	1 784
Pouce Coupe South	7 797	573	313	326	1 212
Provost	11 579	838	543	391	1 772
Rainbow	6 976	970	638	782	2 390
Rainbow South	2 884	691	315	356	1 362
Red Rock	7 672	579	255	216	1 050
Ricinus	4 069	546	272	467	1 285
Sinclair	8 845	664	281	292	1 237
Sundance	11 403	1 059	455	451	1 966
Swan Hills South	2 654	1 615	739	308	2 662
Sylvan Lake	3 413	518	249	228	995
Valhalla	7 366	1 097	585	854	2 537
Virginia Hills	1 385	690	226	89	1 005
Wapiti	25 338	1 569	663	644	2 876
Waterton	5 256	280	250	1 560	2 090
Wayne-Rosedale	6 651	449	243	269	961
Wembley	2 571	582	340	726	1 648
Westerose South	6 523	1 108	540	524	2 173
Westpem	4 260	905	471	530	1 906

(continued)

Table B.8 Remaining raw reserves of natural gas liquids as of December 31, 2010 (continued)

Field	Remaining reserves of marketable gas ($10^6 m^3$)	($10^3 m^3$ liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Wild River	26 388	2 378	988	1 469	4 834
Willesden Green	11 983	2 121	990	951	4 062
Wilson Creek	3 498	501	258	294	1 053
Subtotal	**404 401**	**47 496**	**23 848**	**30 308**	**101 652**
All other fields	**620 694**	**27 718**	**15 592**	**18 430**	**61 740**
Total	**1 025 095**	**75 214**	**39 440**	**48 738**	**163 392**

APPENDIX C

Appendix C CD—Basic Data Tables

ERCB staff developed the databases used to prepare this reserves report and CD. Input was also obtained from the National Energy Board (NEB) through an ongoing process of crude oil, natural gas, and crude bitumen studies. The crude oil and natural gas reserves data tables present the official reserve estimates of both the ERCB and NEB for the province of Alberta.

Basic Data Tables

The conventional oil and conventional natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2009 on the CD that accompanies this report (available for $546 from ERCB Information Services). The individual oil and gas pool values are presented on the first worksheet of each spreadsheet. Oilfield, and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place to allow for easy scrolling. All crude oil and natural gas pools are listed first alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first. Additionally, the crude bitumen in-place resources and basic data presented in Tables B.1 and B.2 are included in Excel format on the CD.

Crude Oil Reserves and Basic Data

The crude oil reserves and basic data spreadsheet is similar to the data table in last year's report and contains all nonconfidential pools in Alberta.

Reserves data for single- and multi-mechanism pools are presented in separate columns. The total record contains the summation of the multi-mechanism pool reserves data. These data appear in the pool column, which can be used for determining field and provincial totals. The mechanism type is displayed with the names.

Provincial totals for light-medium and heavy oil pools are presented separately on the provincial total worksheet.

Natural Gas Reserves and Basic Data

The natural gas reserves and basic data spreadsheet in this report is similar to last year's report and contains all nonconfidential pools in Alberta.

Basic reserves data are split into two columns: pools (individual, undefined, and total records) and member pools (separate gas pools overlying a single oil pool or individual gas pools that have been commingled). The total record contains a summation of the reserves data for all of the related members. Individual pools have a sequence code of 000; undefined pools have a pool code ending in 98 and a unique pool sequence code other than 000; and the total records have a sequence code of 999. Member pools and the total record have the same pool code, with each member pool having a unique pool sequence code and the total record having a sequence code of 999.

Crude Bitumen Resources and Basic Data

The Crude Bitumen In-Place Resources and Basic Data spreadsheet is similar to the data tables in last year's report. The oil sands area, oil sands deposit, overburden/zone, oil sands sector/pool, and resource determination method are listed in separate columns.

General Abbreviations Used in the Reserves and Basic Data Files

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
BDY	boundary
BELL	Belloy
BER	beyond economic reach
BLAIR	Blairmore
BLSKY OR BLSK	Bluesky
BLUE	Blueridge
BNFF	Banff
BOW ISL or BI	Bow Island
BR	Belly River
BSL COLO	Basal Colorado
BSL MANN, BMNV or BMN	Basal Mannville
BSL QTZ	Basal Quartz
CADM or CDN	Cadomin
CARD	Cardium
CDOT	Cadotte
CH LK	Charlie Lake
CLWTR	Clearwater
CLY or COL	Colony
CMRS	Camrose
COMP	compressibility
DBLT	Debolt
DETR	Detrital
DISC YEAR	discovery year
ELRSL, ELERS or ELRS	Ellerslie

ELTN or ELK	Elkton
ERSO	enhanced-recovery scheme is in operation but no additional established reserves are attributed
FALH	Falher
FRAC	fraction
GEN PETE or GEN PET	General Petroleum
GETH or GET	Gething
GLAUC or GLC	Glauconitic
GLWD	Gilwood
GOR	gas-oil ratio
GRD RAP or GRD RP	Grand Rapids
GROSS HEAT VALUE	gross heating value
GSMT	Grosmont
ha	hectare
HFWY	Halfway
INJ	injected
I.S.	integrated scheme
JUR or J	Jurassic
KB	kelly bushing
KISK	Kiskatinaw
KR	Keg River
LED	Leduc
LF	load factor
LIV	Livingston
LLOYD	Lloydminster
LMNV, LMN or LM	Lower Mannville
LOC EX PROJECT	local experimental project
LOC U	local utility
LOW or L	lower
LUSC	Luscar
MANN or MN	Mannville
MCM	McMurray
MED HAT	Medicine Hat
MID or M	middle
MILK RIV	Milk River
MOP	maximum operating pressure
MSKG	Muskeg
MSL	mean sea level
NGL	natural gas liquids
NIKA	Nikanassin
NIS	Nisku
NO.	number
NON-ASSOC	nonassociated gas

NORD	Nordegg
NOTIK, NOTI or NOT	Notikewin
OST	Ostracod
PALL	Palliser
PEK	Pekisko
PM-PN SYS	Permo-Penn System
RF	recovery factor
RK CK	Rock Creek
RUND or RUN	Rundle
SA	strike area
SATN	saturation
SD	sandstone
SE ALTA GAS SYS (MU)	Southeastern Alberta Gas System - commingled
SG	gas saturation
SHUN	Shunda
SL	surface loss
SL PT	Slave Point
SOLN	solution gas
SPKY	Sparky
ST. ED	St. Edouard
SULPT	Sulphur Point
SUSP	suspended
SW	water saturation
SW HL	Swan Hills
TEMP	temperature
TOT	total
TV	Turner Valley
TVD	true vertical depth
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
VOL	volume
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
WTR DISP	water disposal
WTR INJ	water injection
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks

Appendix D Drilling Activity in Alberta

Table D.1 Development and exploratory wells, 1972-2010; number drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
1972	438	*	**	672	1 468	69	**	318	1 208	507	**	990	2 676
1973	472	*	**	898	1 837	109	**	476	1 676	581	**	1 374	3 513
1974	553	*	**	1 222	2 101	82	**	446	1 388	635	**	1 668	3 489
1975	583	*	**	1 367	2 266	81	**	504	1 380	664	**	1 871	3 646
1976	440	*	**	2 044	2 887	112	**	1 057	2 154	552	**	3 101	5 041
1977	524	*	**	1 928	2 778	178	**	1 024	2 352	702	**	2 952	5 130
1978	708	*	**	2 091	3 186	236	**	999	2 387	944	**	3 090	5 573
1979	953	*	**	2 237	3 686	297	**	940	2 094	1 250	**	3 177	5 780
1980	1 229	*	**	2 674	4 425	377	**	1 221	2 623	1 606	**	3 895	7 048
1981	1 044	*	**	2 012	3 504	381	**	1 044	2 337	1 425	**	3 056	5 841
1982	1 149	*	**	1 791	3 353	414	**	620	1 773	1 563	**	2 411	5 126
1983	1 823	*	**	791	2 993	419	**	300	1 373	2 242	**	1 091	4 366
1984	2 255	*	**	911	3 724	582	**	361	1 951	2 837	**	1 272	5 675
1985	2 101	975	229	1 578	5 649	709	593	354	2 827	2 810	1 797	1 932	8 476
1986	1 294	191	75	660	2 783	452	171	311	1 726	1 746	437	971	4 509
1987	1 623	377	132	549	3 212	553	105	380	1 970	2 176	614	929	5 182
1988	1 755	660	54	871	4 082	526	276	610	2 535	2 281	990	1 481	6 617
1989	869	37	24	602	1 897	382	246	660	2 245	1 251	307	1 262	4 142
1990	804	69	30	715	1 999	401	122	837	2 308	1 205	221	1 552	4 307
1991	1 032	91	13	544	2 089	346	51	566	1 808	1 378	155	1 110	3 897
1992	1 428	101	2	335	2 306	368	13	387	1 497	1 796	116	722	3 803
1993	2 402	290	6	1 565	4 919	549	5	763	2 350	2 951	301	2 328	7 269
1994	1 949	143	0	2 799	5 876	700	53	1 304	3 250	2 649	196	4 103	9 126
1995	2 211	828	1	1 910	5 939	496	222	872	2 542	2 707	1 051	2 782	8 481
1996	2 987	1 675	15	1 932	7 728	583	459	732	2 668	3 570	2 149	2 664	10 396
1997	4 210	2 045	8	2 704	10 275	837	645	614	2 937	5 047	2 698	3 318	13 212
1998	1 277	270	6	3 083	5 166	386	500	1 430	3 007	1 663	776	4 513	8 173
1999	1 311	502	0	4 679	6 988	285	351	1 620	2 905	1 596	853	6 299	9 893
2000	2 052	890	2	5473	8 955	466	576	2 033	3 690	2 518	1 468	7 506	12 645
2001	1 703	818	4	7 089	10 127	418	1 115	2 727	4 927	2 121	1 937	9 816	15 054
2002	1 317	1 056	8	5 921	8 586	345	1 222	2 246	4 231	1 662	2 286	8 167	12 817

(continued)

Table D.1 Development and exploratory wells, 1972-2010; number drilled annually (continued)

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen		Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
		Commercial	Experimental										
2003	1 922	1 000	0	9 705	12 982	441	1 610	2 877	5 328	2 363	2 610	12 582	18 310
2004	1 516	859	0	10 768	13 502	486	1 739	3 179	5 742	2 002	2 598	13 947	19 244
2005	1 748	1 158	2	11 157	14 559	554	1 496	3 454	5 825	2 302	2 656	14 611	20 384
2006	1 583	1 147	0	9 883	12 975	601	2 195	3 258	6 323	2 184	3 342	13 141	19 298
2007	1 376	1 376	0	8 174	11 314	393	2 919	1 738	5 388	1 769	4 295	9 912	16 702
2008	1 420	1 205	4	6 838	9 945	300	3 428	1 099	5 076	1 720	4 637	7 937	15 021
2009	785	941	0	3 000	5 050	126	1 270	398	1 930	911	2 211	3 398	6 980
2010	1 979	1 336	0	3 408	7 103	280	1 331	391	2 130	2 259	2 697	3 799	9 233

Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2010 - Alberta Drilling Activity Monthly Statistics (ST59).

[a] Includes unsuccessful, service, and suspended wells.

[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.

* Included in oil.

** Not available.

Table D.2 Development and exploratory wells, 1972-2010; kilometres drilled annually

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen		Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
		Commercial	Experimental										
1972	608	*	**	461	1 503	99	**	350	1 569	707	**	811	3 072
1973	659	*	**	635	2 053	127	**	465	1 802	786	**	1 100	3 855
1974	708	*	**	816	2 076	115	**	465	1 580	823	**	1 281	3 656
1975	686	*	**	1 020	2 192	107	**	494	1 457	793	**	1 514	3 649
1976	564	*	**	1 468	2 910	147	**	897	1 965	711	**	2 365	4 875
1977	668	*	**	1 299	2 926	188	**	1 029	2 324	856	**	2 328	5 250
1978	934	*	**	1 463	3 298	333	**	1 267	2 828	1 267	**	2 730	6 126
1979	1 387	*	**	1 713	3 840	507	**	1 411	3 073	1 894	**	3 124	6 913
1980	1 666	*	**	2 134	4 716	614	**	1 828	3 703	2 280	**	3 962	8 419
1981	1 270	*	**	1 601	3 598	573	**	1 442	3 172	1 843	**	3 043	6 770
1982	1 570	*	**	1 280	3 601	670	**	747	2 305	2 240	**	2 027	5 906
1983	2 249	*	**	758	3 834	610	**	407	1 819	2 859	**	1 165	5 653
1984	2 768	*	**	776	4 823	774	**	464	2 407	3 542	**	1 240	7 230
1985	3 030	577	123	1 389	6 373	1 048	99	465	2 962	4 078	799	1 854	9 335
1986	2 000	116	37	742	3 809	622	41	398	2 037	2 622	194	1 140	5 846

(continued)

Table D.2 Development and exploratory wells, 1972-2010; kilometres drilled annually (continued)

	Development					Exploratory				Total			
	Successful oil	Crude bitumen		Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
Year		Commerical	Experimental										
1987	2 302	209	68	730	4 250	793	16	518	2 486	3 095	293	1 248	6 736
1988	2 318	376	31	1 049	5 018	695	65	739	2 870	3 013	472	1 788	7 888
1989	1 130	24	13	733	2 622	382	33	747	2 353	1 512	70	1 480	4 975
1990	1 099	46	22	886	2 834	479	18	860	2 339	1 578	86	1 746	5 173
1991	1 307	62	6	641	2 720	346	14	615	1 979	1 653	82	1 256	4 699
1992	1 786	65	2	399	2 965	470	4	409	1 650	2 256	71	808	4 615
1993	3 044	193	7	1 616	5 850	695	2	773	2 585	3 739	202	2 389	8 435
1994	2 696	96	0	2 876	6 958	922	11	1 389	3 702	3 618	107	4 265	10 660
1995	2 856	620	1	1 969	6 702	624	52	995	2 791	3 480	673	2 964	9 493
1996	3 781	1 202	13	2 030	8 372	724	148	814	2 733	4 505	1 363	2 844	11 105
1997	5 380	1 561	8	2 902	11 383	1 080	142	733	2 928	6 460	1 711	3 635	14 311
1998	1 839	445	8	3 339	6 398	537	119	1 780	3 216	2 376	572	5 119	9 614
1999	1 566	401	0	4 319	6 838	390	60	1 620	3 041	1 956	461	5 939	9 879
2000	2 820	940	2	5 169	9 638	582	131	2 486	3 931	3 402	1 073	7 655	13 569
2001	2 454	834	25	6 846	10 840	603	253	3 219	4 857	3 057	1 112	10 065	15 697
2002	1 852	1 043	2	5 983	9 272	462	315	2 541	3 813	2 314	1 360	8 524	13 085
2003	2 727	1 032	0	9 610	13 825	573	388	3 347	4 799	3 300	1 420	12 957	18 624
2004	2 095	1 000	0	10 767	14 284	663	354	3 905	5 297	2 758	1 354	14 672	19 581
2005	2 534	1 353	3	11 519	16 009	792	338	4 616	6 117	3 326	1 694	16 135	22 126
2006	2 263	1 305	0	10 549	14 549	903	496	4 720	6 477	3 166	1 801	15 269	21 026
2007	2 045	1 550	0	8 447	12 469	623	751	2 731	4 582	2 668	2 301	11 178	17 051
2008	2 159	1 379	2	7 790	11 758	447	929	1 726	3 478	2 606	2 310	9 516	15 236
2009	1 257	1 033	0	3 852	6 468	194	380	804	1 619	1 451	1 413	4 656	8 087
2010	3 809	1 336	0	5 134	10 653	514	461	848	1 965	4 323	1 797	5 982	12 618

Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2010 - Alberta Drilling Activity Monthly Statistics (ST59)

[a] Includes unsuccessful, service, and suspended wells

[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production

* Included in oil;

** Not available

APPENDIX E

Appendix E Crude Bitumen Pay Thickness and Geologic Structure Contour Maps

This appendix contains geological maps from the Crude Bitumen Section that have appeared in previous *ST98: Alberta's Energy Reserves and Supply/Demand Outlook* reports. These are the maps that the most recent determinations of in-place resources are based on. Any new mapping will be described in the main body of *ST98* in the first year of reporting.

Regional Map

Sub-Cretaceous Unconformity

The sub-Cretaceous unconformity is the stratigraphic surface that forms the base on which the bitumen-bearing Cretaceous sediments were deposited. **Figure AE.1** is a structure contour map of that surface as it would have appeared at the end of Bluesky/Wabiskaw time. The parts of the Nisku and Grosmont Formations that are bitumen-bearing are outlined on this map. These Devonian carbonate formations subcrop along the sub-Cretaceous surface and contain bitumen in an updip location along the subcrop edge. Of particular note are the areas on this map identified as having a relative subsea elevation of greater than zero. These areas were still emergent at the end of Bluesky/Wabiskaw time and would have existed as islands within the transgressing northern Boreal Sea.

Peace River Oil Sands Area

Peace River Bluesky-Gething Deposit

The Bluesky-Gething deposit was reassessed for year-end 2006. **Figure AE.2** is the bitumen pay thickness map for the Bluesky-Gething deposit based on cutoffs of 6 mass per cent and 1.5 metres (m) thickness. The Bluesky-Gething is mapped as a single bitumen zone, so that the full extent of the deposit at 6 mass per cent can be shown. Also shown on **Figure AE.2** are the paleotopographic highlands as they would have existed at the time of the end of the deposition of the Bluesky Formation. These highlands, composed of carbonate rocks of Devonian and Mississippian age, controlled the deposition of the Bluesky and correspondingly the extent of the reservoir. As oil migrated updip, it became trapped beneath the overlying Wilrich shales and against these highlands, where it was eventually biodegraded into bitumen.

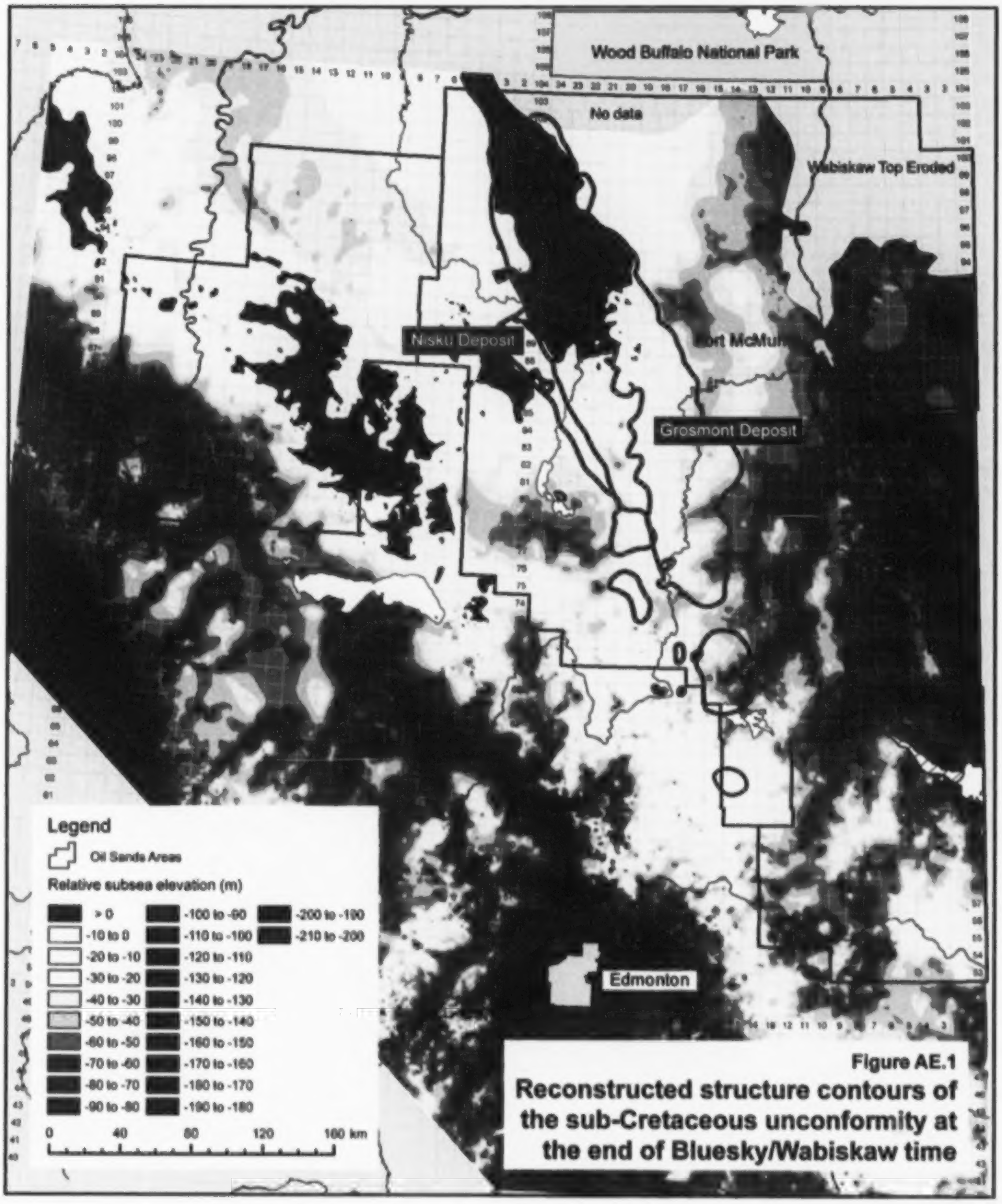
Wood Buffalo National Park
No data
Wabiskaw Top Eroded
Nisku Deposit
Fort McMu
Grosmont Deposit
Edmonton
Legend
Oil Sands Areas
Relative subsea elevation (m)
> 0
-10 to 0
-20 to -10
-30 to -20
-40 to -30
-50 to -40
-60 to -50
-70 to -60
-80 to -70
-90 to -80
-100 to -90
-110 to -100
-120 to -110
-130 to -120
-140 to -130
-150 to -140
-160 to -150
-170 to -160
-180 to -170
-190 to -180
-200 to -190
-210 to -200
0
40
80
120
160 km

Figure AE.1

Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

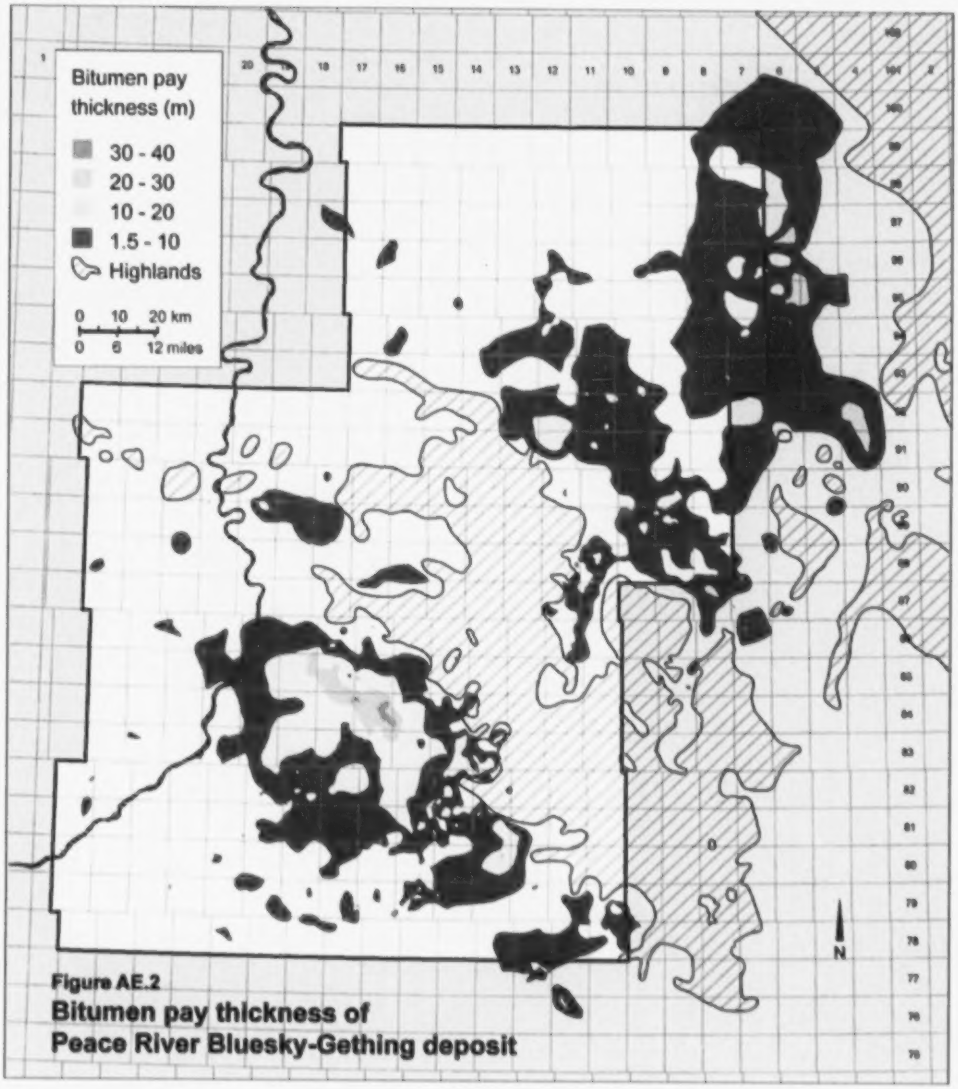

Figure AE.2
Bitumen pay thickness of Peace River Bluesky-Gething deposit

Athabasca Oil Sands Area

Athabasca Grosmont Deposit

In 2009, the ERCB updated the previous (1990) resource assessment of the Athabasca Grosmont deposit. Over 1330 wells were used within the study area, which extended from Township 62 to 103 and Range 13, West of the 4th Meridian, to 6W5M.

The Grosmont Formation is a late-Devonian shallow marine to peritidal platform carbonate consisting of four recognizable units within the deposit: the Grosmont A, B, C, and D. All of the hydrocarbons are located in an updip position, structurally trapped along the erosional edge and contained by the overlying

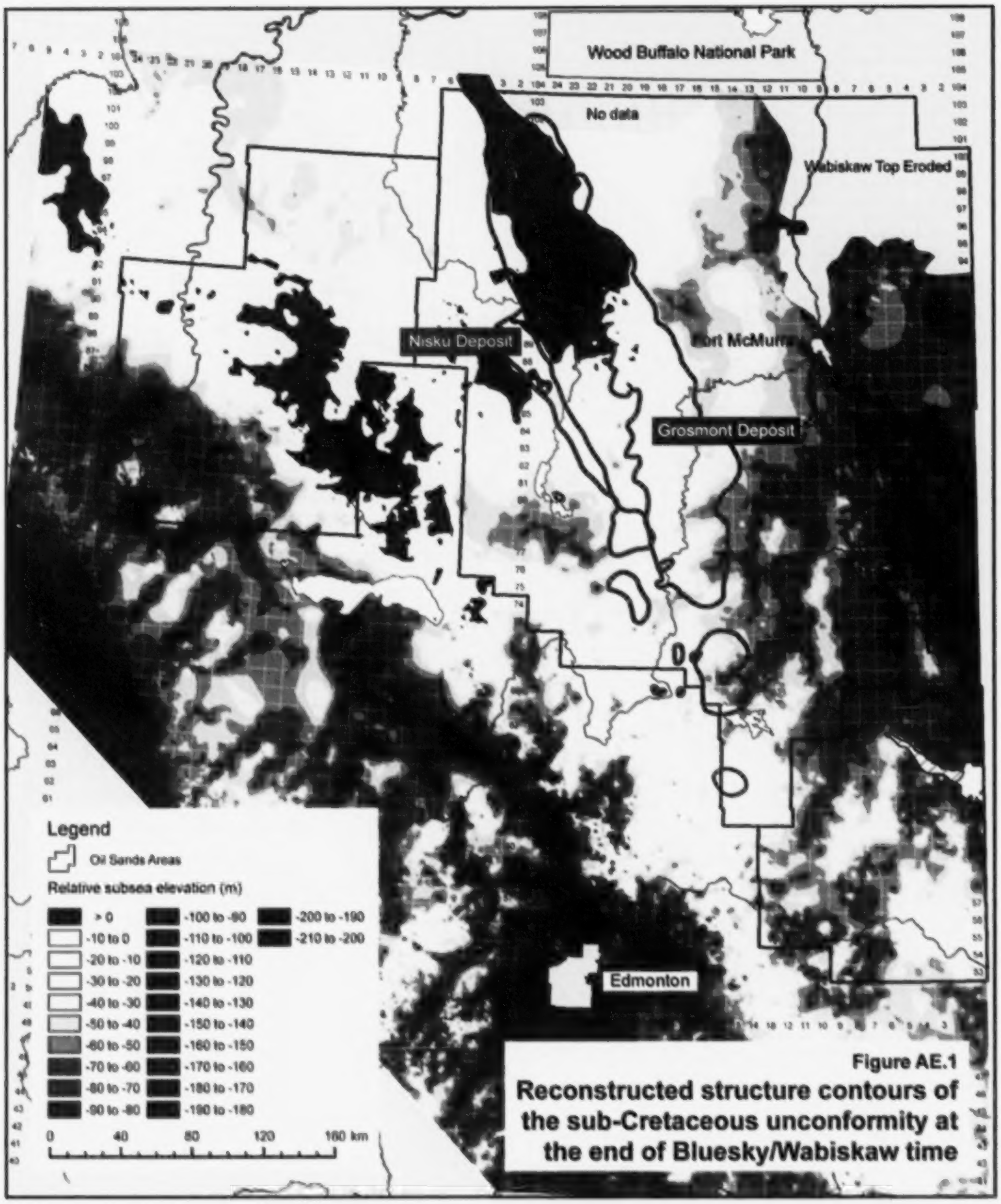
Wood Buffalo National Park
No data
Wabiskaw Top Eroded
Fort McMurray
Nisku Deposit
Grosmont Deposit
Edmonton
Legend
Oil Sands Areas
Relative subsea elevation (m)
> 0
-10 to 0
-20 to -10
-30 to -20
-40 to -30
-50 to -40
-60 to -50
-70 to -60
-80 to -70
-90 to -80
-100 to -90
-110 to -100
-120 to -110
-130 to -120
-140 to -130
-150 to -140
-160 to -150
-170 to -160
-180 to -170
-190 to -180
-200 to -190
-210 to -200
0
40
80
120
160 km

Figure AE.1
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

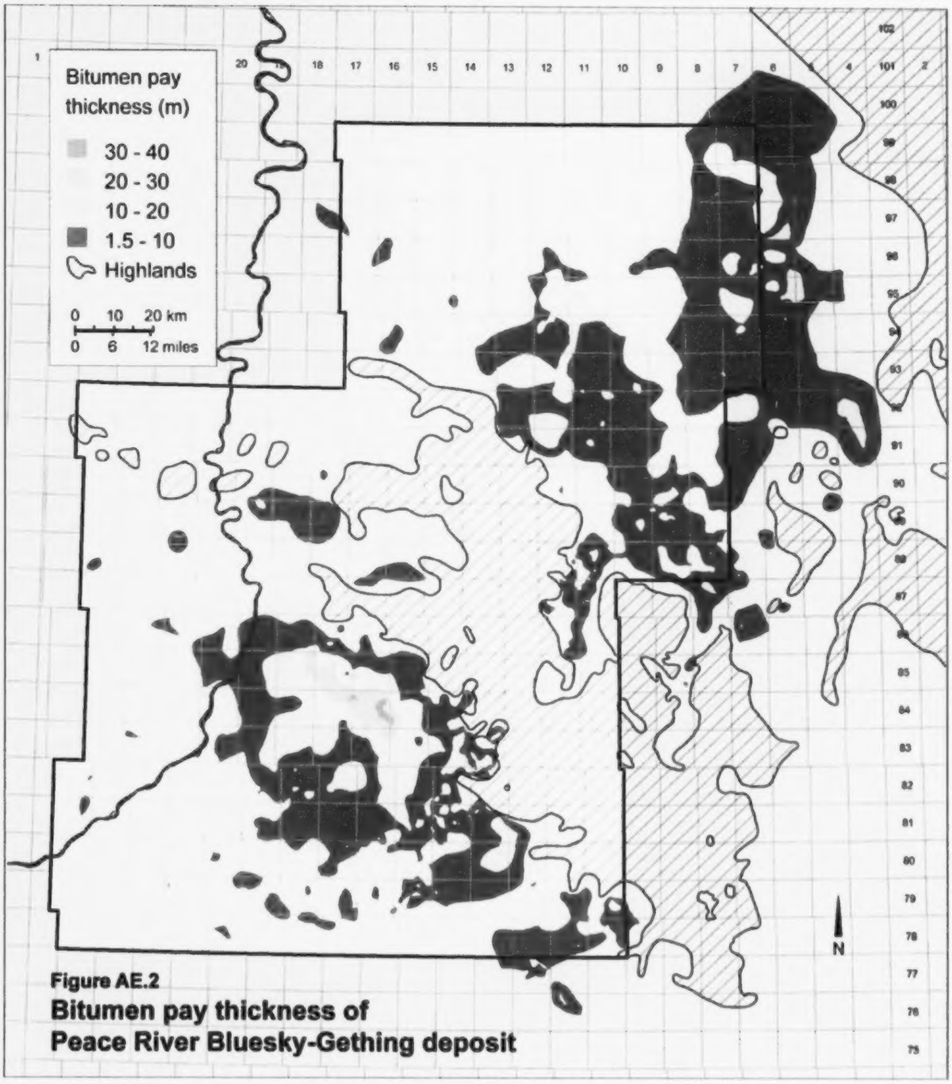
Bitumen pay thickness (m)
30 - 40
20 - 30
10 - 20
1.5 - 10
Highlands
0 10 20 km
0 6 12 miles
N
1
20
19
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
2
102
101
100
99
98
97
96
95
94
93
92
91
90
89
88
87
86
85
84
83
82
81
80
79
78
77
76
75

Figure AE.2
Bitumen pay thickness of Peace River Bluesky-Gething deposit

Athabasca Oil Sands Area

Athabasca Grosmont Deposit

In 2009, the ERCB updated the previous (1990) resource assessment of the Athabasca Grosmont deposit. Over 1330 wells were used within the study area, which extended from Township 62 to 103 and Range 13, West of the 4th Meridian, to 6W5M.

The Grosmont Formation is a late-Devonian shallow marine to peritidal platform carbonate consisting of four recognizable units within the deposit: the Grosmont A, B, C, and D. All of the hydrocarbons are located in an updip position, structurally trapped along the erosional edge and contained by the overlying

Clearwater Formation. **Figure AE.3** is the cumulative bitumen net pay isopachs for the entire Grosmont deposit.

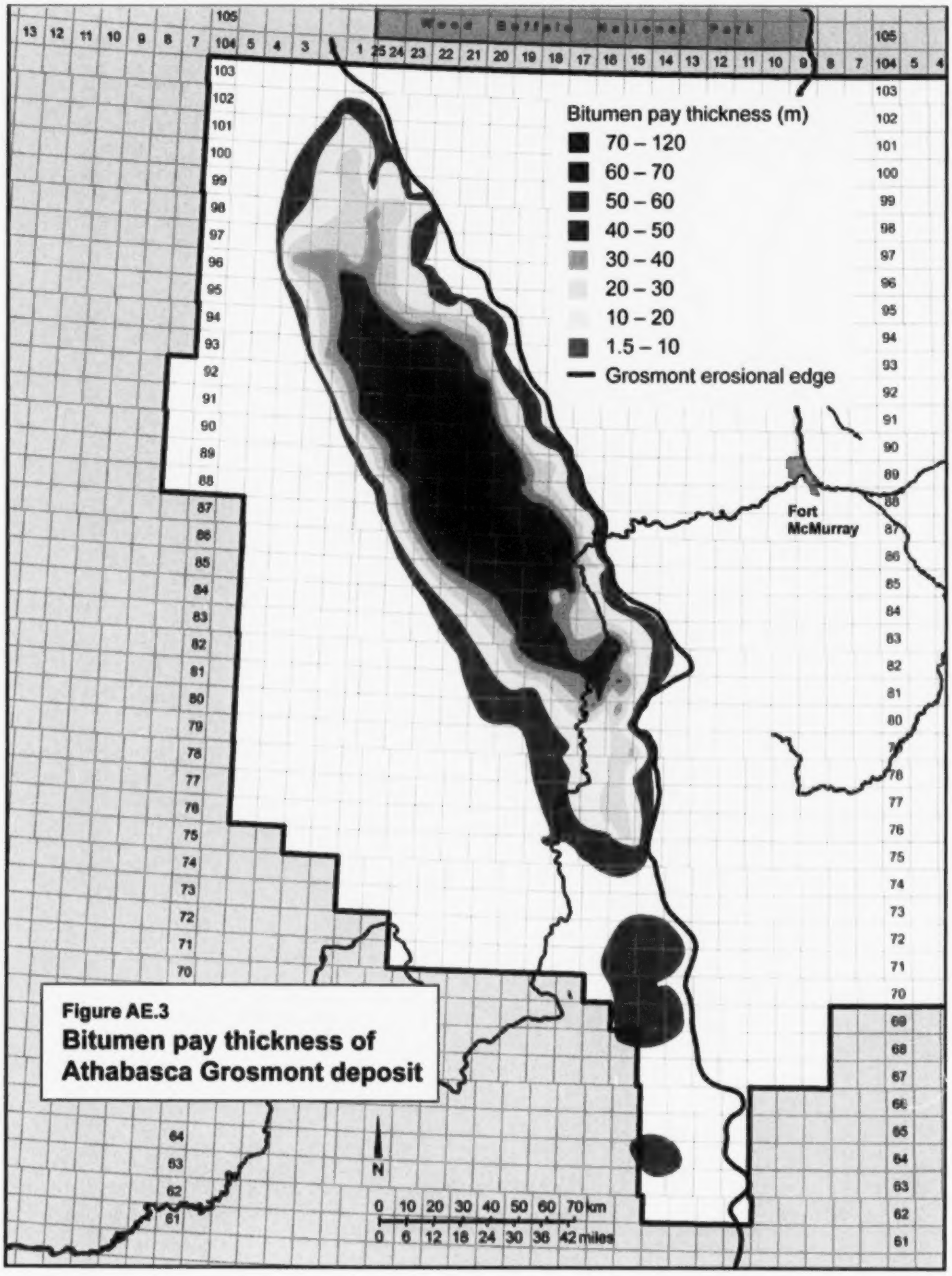
Wood Buffalo National Park
Bitumen pay thickness (m)
70 – 120
60 – 70
50 – 60
40 – 50
30 – 40
20 – 30
10 – 20
1.5 – 10
Grosmont erosional edge
Fort McMurray
N
0 10 20 30 40 50 60 70 km
0 6 12 18 24 30 36 42 miles

Figure AE.3
Bitumen pay thickness of Athabasca Grosmont deposit

Athabasca Wabiskaw-McMurray Deposit

In 2003, the ERCB completed a reassessment of the Wabiskaw-McMurray using geological information from over 13 000 wells and bitumen content evaluations from over 9000 wells to augment the over 7000 boreholes already assessed within the surface mineable area (SMA; see below for details). In 2005 and 2007, nearly 700 and 2700 new wells respectively, mostly outside the SMA, were added to the reassessment, and the volumes and maps were revised. In 2008, about 2500 additional wells outside the SMA and about 18 000 wells inside the SMA were added. In 2009, about 1700 wells, including about 350 from within the SMA, were added.

Figure AE.4 is a bitumen pay thickness map of the Wabiskaw-McMurray deposit revised for year-end 2009 based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map, the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval. Also shown is the extent of the SMA, an ERCB-defined area of 51½ townships north of Fort McMurray covering that part of the Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. This designation is for resource administration purposes and carries no regulatory authority. That is to say that while mining activities are likely to be confined to the SMA, they may occur outside the area's boundaries, while in situ activities may occur within the SMA. Because the extent of the SMA is defined using township boundaries, it incorporates a few areas containing deeper bitumen resources that are more amenable to in situ recovery. The ERCB has generated a line that generally separates the mineable portion of the deposit from the in situ portion, and that line is shown in **Figure AE.4**.

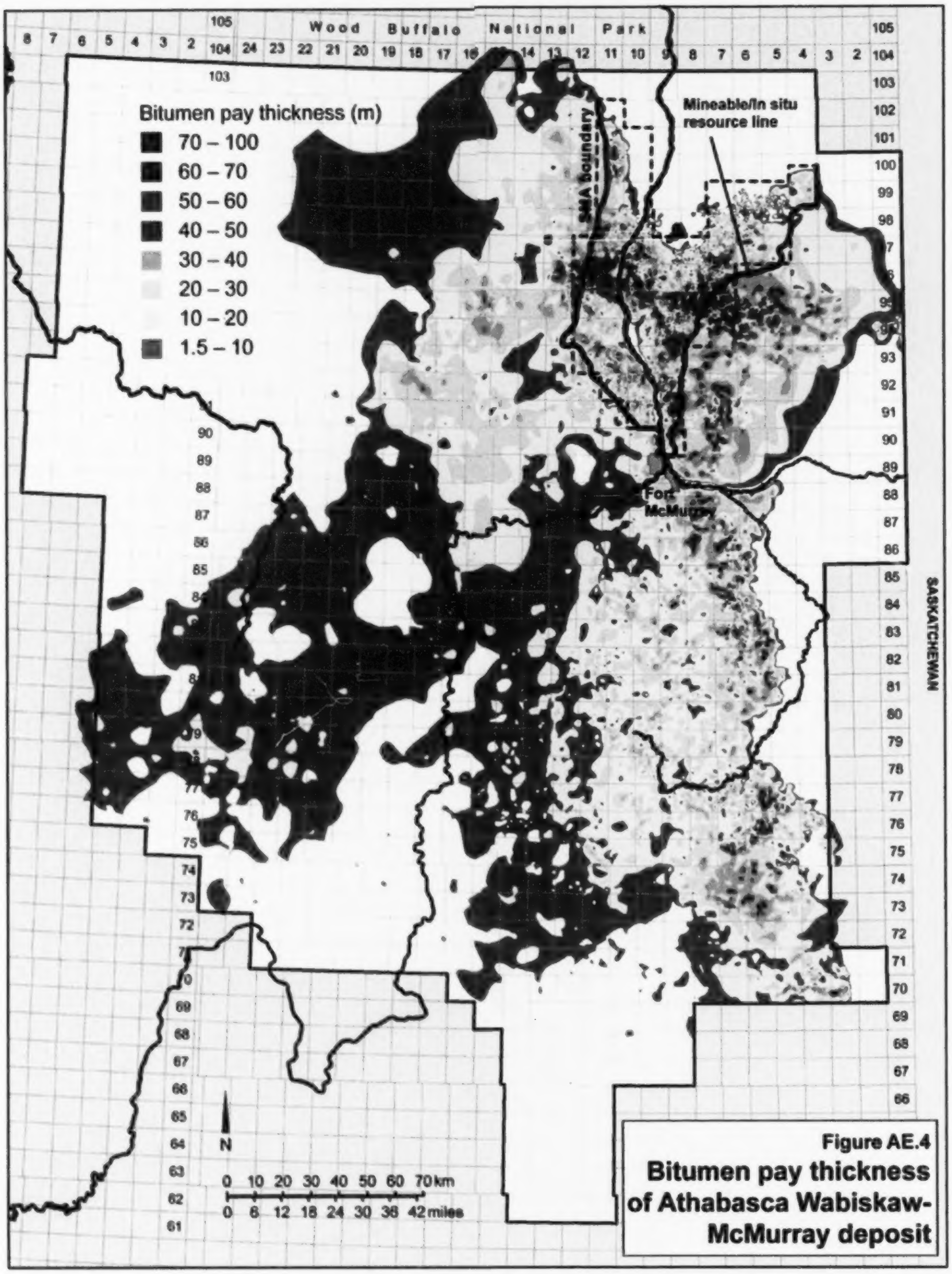
Wood Buffalo National Park
Bitumen pay thickness (m)
70 – 100
60 – 70
50 – 60
40 – 50
30 – 40
20 – 30
10 – 20
1.5 – 10
SMA boundary
Mineable/In situ resource line
Fort McMurray
SASKATCHEWAN
N
0 10 20 30 40 50 60 70 km
0 6 12 18 24 30 36 42 miles
8 7 6 5 4 3 2 104 24 23 22 21 20 19 18 17 16 14 13 12 11 10 9 8 7 6 5 4 3 2 104
105 103 102 101 100 99 98 93 92 91 90 89 88 87 86 85 84 83 82 81 80 79 78 77 76 75 74 73 72 71 70 69 68 67 66 65 64 63 62 61

Figure AE.4
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

Cold Lake Oil Sands Area

Sub-Cretaceous Unconformity

Figure AE.5 is a map of the reconstructed structure contours for the sub-Cretaceous unconformity in the northern part of the Cold Lake Oil Sands Area as they would have been at the beginning of deposition of the Mannville Clearwater Formation.

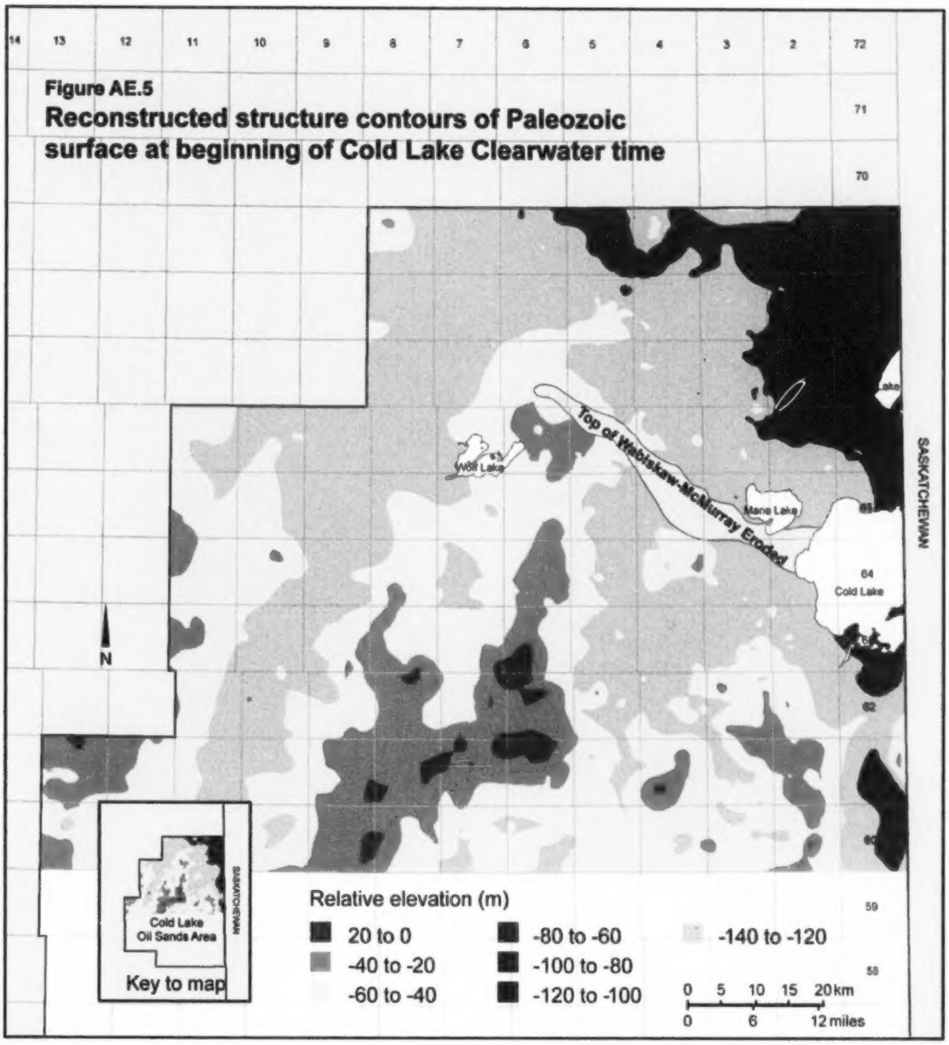

Figure AE.5

Reconstructed structure contours of Paleozoic surface at beginning of Cold Lake Clearwater time

14
13
12
11
10
9
8
7
6
5
4
3
2
72
71
70
64
62
60
59
58
Wolf Lake
Top of Wabiskaw-McMurray Eroded
Marie Lake
Cold Lake
Lake
SASKATCHEWAN
N
Cold Lake Oil Sands Area
SASKATCHEWAN
Key to map
Relative elevation (m)
20 to 0
-40 to -20
-60 to -40
-80 to -60
-100 to -80
-120 to -100
-140 to -120
0 5 10 15 20 km
0 6 12 miles

Cold Lake Wabiskaw-McMurray Deposit

For year-end 2005, the ERCB reassessed the northern portion of the Cold Lake Wabiskaw-McMurray deposit. Stratigraphic information and detailed petrophysical evaluations from almost 400 wells were used in this reassessment. **Figure AE.6** is the bitumen pay thickness map for the Cold Lake Wabiskaw-McMurray deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Although the Wabiskaw-McMurray contains some regionally mappable internal seals, and therefore several bitumen zones, this map was produced as a single bitumen zone to provide a regional overview of the distribution of the bitumen-saturated sands. A cutoff of 6 mass per cent bitumen was used.

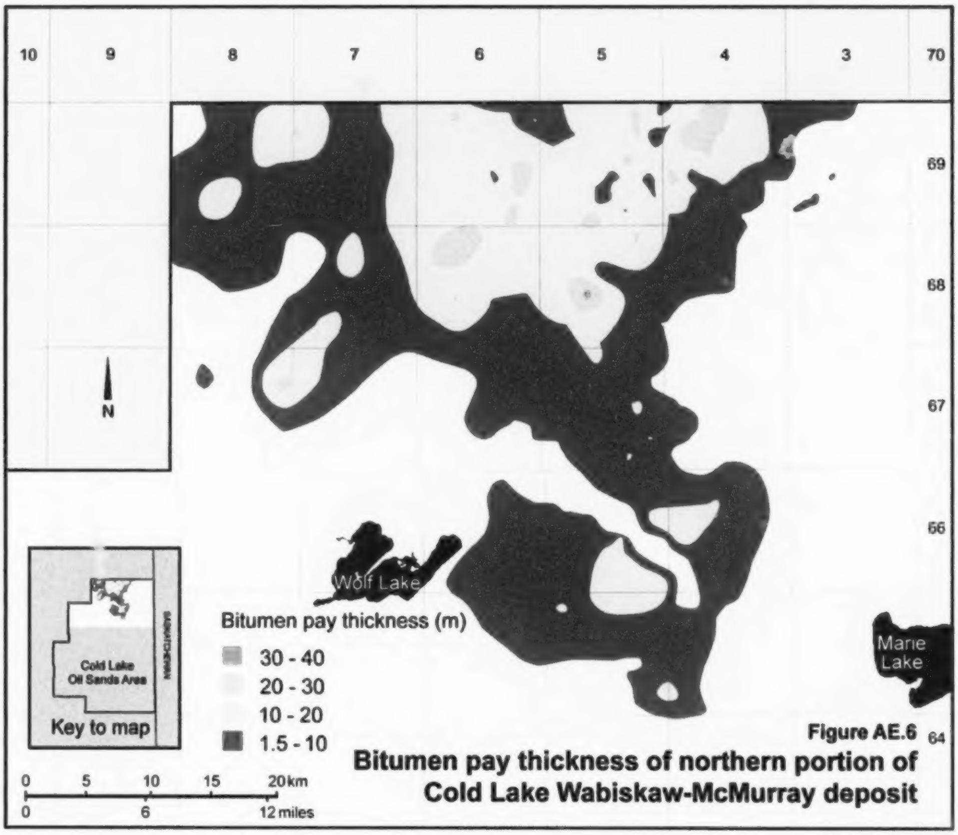
10
9
8
7
6
5
4
3
70
69
68
67
66
64
N
Wolf Lake
Marie Lake
Cold Lake Oil Sands Area
SASKATCHEWAN
Key to map
Bitumen pay thickness (m)
▨ 30 - 40
20 - 30
10 - 20
■ 1.5 - 10
0 5 10 15 20km
0 6 12 miles

Figure AE.6
Bitumen pay thickness of northern portion of Cold Lake Wabiskaw-McMurray deposit

Cold Lake Clearwater Deposit

For year-end 2005, the ERCB completed a reassessment of the Clearwater deposit. **Figure AE.7** is a bitumen pay thickness map for the Clearwater deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the Clearwater does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

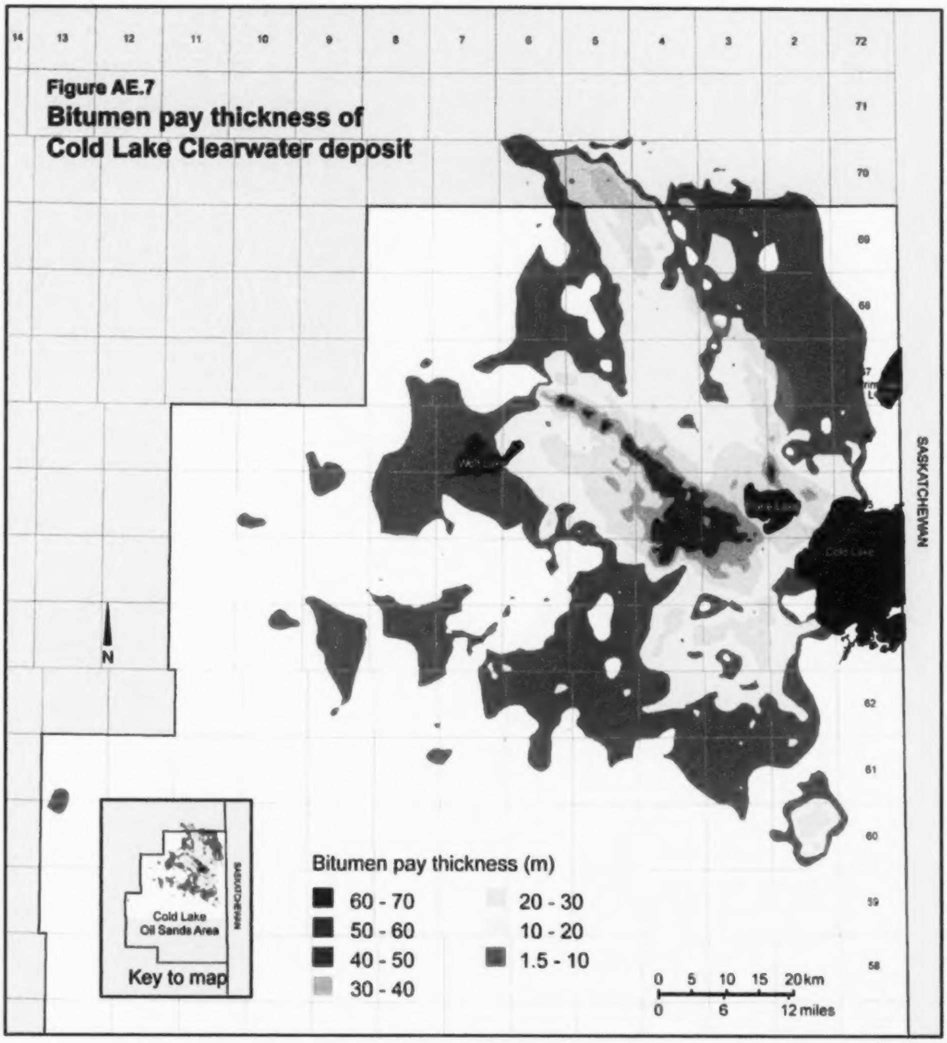

Figure AE.7
Bitumen pay thickness of Cold Lake Clearwater deposit

14
13
12
11
10
9
8
7
6
5
4
3
2
72
71
70
69
68
67
62
61
60
59
58
SASKATCHEWAN
Cold Lake
N
Cold Lake Oil Sands Area
SASKATCHEWAN
Key to map
Bitumen pay thickness (m)
■ 60 - 70
■ 50 - 60
■ 40 - 50
■ 30 - 40
■ 20 - 30
■ 10 - 20
■ 1.5 - 10
0 5 10 15 20km
0 6 12 miles

Cold Lake Upper and Lower Grand Rapids Deposits

A reassessment for year-end 2009 of the Upper and Lower Grand Rapids deposits included a review of some 12 000 wells for stratigraphic tops and net pay. The study area from Township 52 to 66 replaced the area used in the previous assessment. Stratigraphy and net pay determination were completed for each Grand Rapids zone: Colony, McLaren, Waseca, Sparky, General Petroleum (GP), Rex, and Lloydminster.

Although crude bitumen within both Grand Rapids deposits is pervasive through much of the Cold Lake Oil Sands Area, the developable resource (primary bitumen for the most part) is generally associated with Paleozoic highs. **Figures AE.8** and **AE.9** are maps of the cumulative net pay isopachs for the Upper

Grand Rapids deposit and the Lower Grand Rapids deposit respectively. The net pay interpretations and volumetric calculations were completed for each zone and were then summed for the relevant deposit. The Colony, Waseca, and McLaren are included in the Upper Grand Rapids, and the Sparky, GP, Rex, and Lloydminster are included in the Lower Grand Rapids.

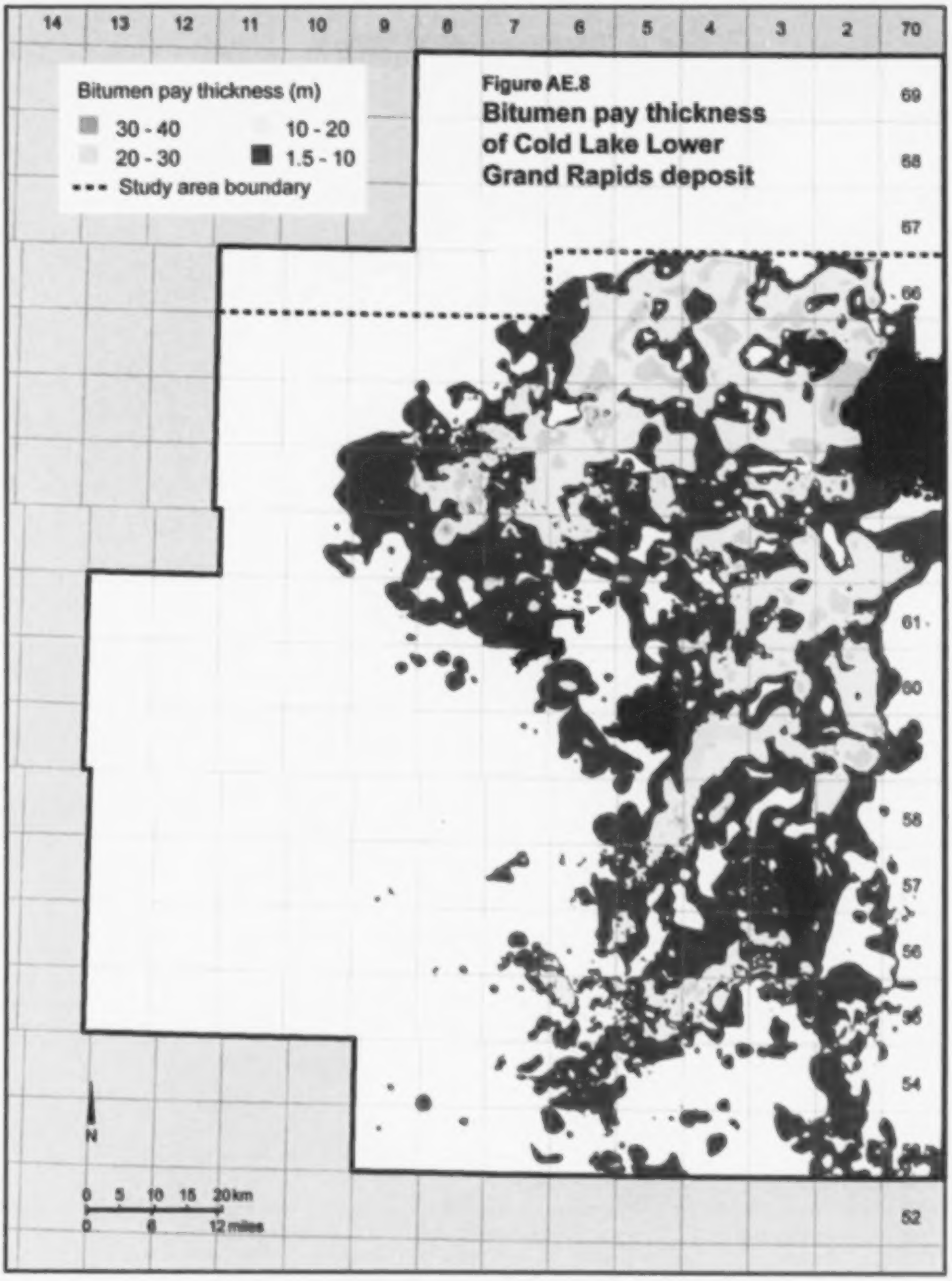
Bitumen pay thickness (m)
▨ 30 - 40
10 - 20
20 - 30
■ 1.5 - 10
--- Study area boundary
14
13
12
11
10
9
8
7
6
5
4
3
2
70
69
68
67
66
61
60
58
57
56
55
54
52
N
0 5 10 15 20km
0 6 12 miles

Figure AE.8
Bitumen pay thickness of Cold Lake Lower Grand Rapids deposit

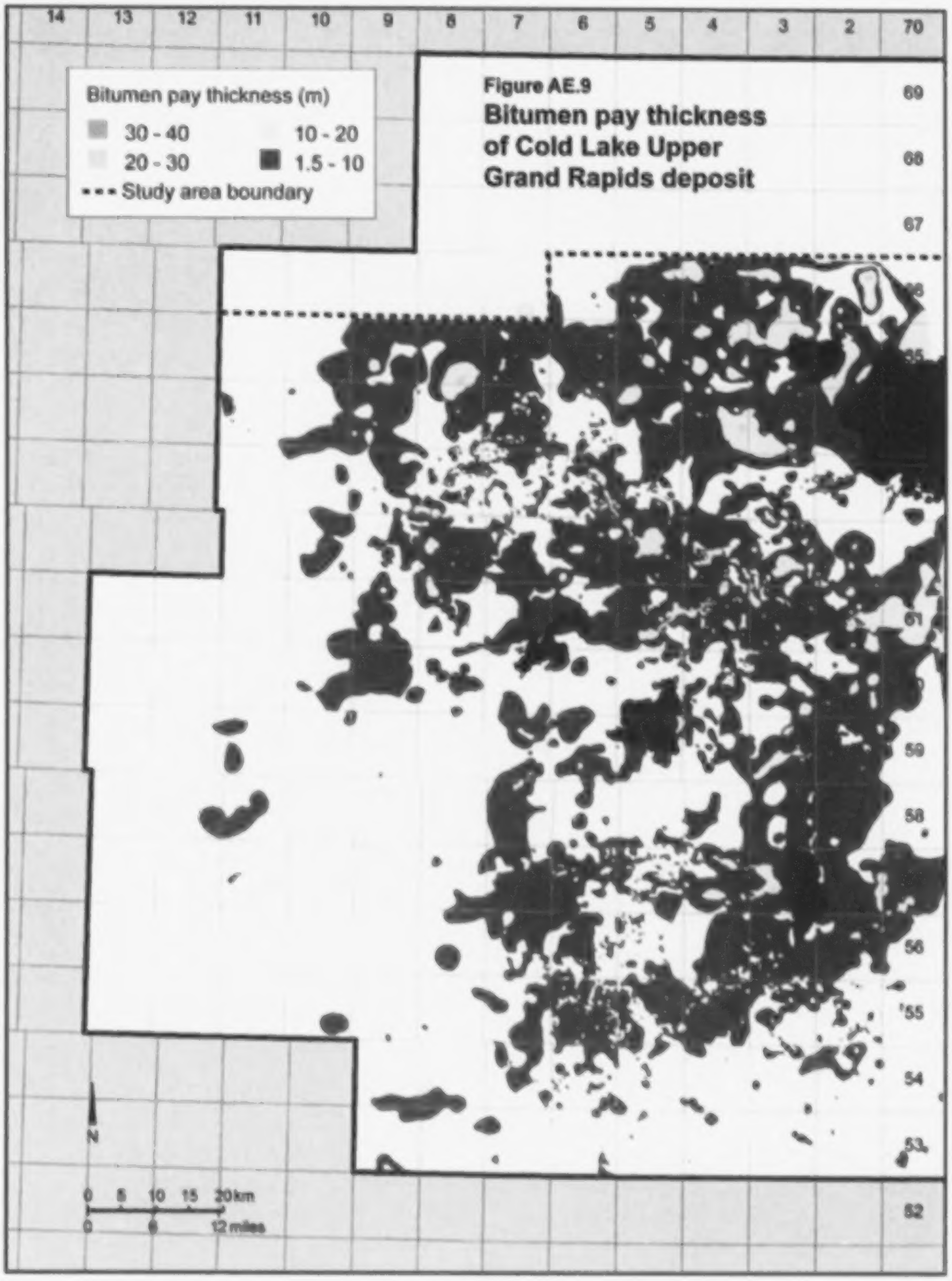
14
13
12
11
10
9
8
7
6
5
4
3
2
70
69
68
67
66
65
61
59
58
56
55
54
53
52
Bitumen pay thickness (m)
30 - 40
10 - 20
20 - 30
1.5 - 10
Study area boundary
N
0 5 10 15 20km
0 6 12 miles

Figure AE.9
Bitumen pay thickness of Cold Lake Upper Grand Rapids deposit

ERCB Energy Resources Conservation Board